

The Potential Role of Hydrogen in India

A pathway for scaling-up low carbon hydrogen across the economy

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THE POTENTIAL ROLE OF HYDROGEN IN INDIA

A PATHWAY FOR SCALING-UP LOW CARBON HYDROGEN ACROSS THE ECONOMY

WILL HALL, THOMAS SPENCER, G RENJITH, SHRUTI DAYAL

ENERGY TRANSITIONS COMMISSION INDIA

Energy Transitions Commission (ETC) India is a research platform based in The Energy and Resources Institute (TERI) in Delhi. ETC India is the Indian chapter of the global Energy Transitions Commission, which is co-chaired by Lord Adair Turner and Dr Ajay Mathur.

ETC India initiated activities in 2017-2018 with a focus on the decarbonization of India's power sector. Whilst that work is still continuing, ETC India has also started to work on industry transition, particularly in the 'harder-to-abate' sectors including iron and steel, cement, and other industry sub-sectors. Work has also begun on cross-cutting themes, such as hydrogen, Carbon Capture, Use and Storage (CCUS), and biomass.

Learn more at: <https://www.teriin.org/energy-transitions>

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Rocky Mountain Institute (RMI)

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FOREWORD



The Energy and Resources Institute (TERI), under our Energy Transitions Commission India work programme, has been assessing technological and economic trends in various energy-producing and consuming sectors so as to advance our understanding of the role of key low carbon technologies in decarbonizing the Indian energy system. Over the past couple of years, this has included detailed modelling of the Indian power system, as well as technology pathways for the heavy industry sectors, such as iron and steel.

From this analysis and TERI's broader work on transport systems, the balance of evidence suggests that renewable electricity, electricity storage, and hydrogen, along with biomass-based electricity and fuels, are the most viable energy options for India in a zero-carbon emissions economy. It turns out that hydrogen has the potential to play a major role across a number of sectors. As a result, we felt it was important to conduct a holistic assessment of hydrogen production and use for the Indian context.

Interest around the potential role of hydrogen in the transition to zero carbon energy systems is growing. Recent years have seen increasing international commitments, industry activity, and civil society interest. It is important that India remains ahead of the curve on clean energy technology development, investing early in research and manufacturing capability to maximize domestic benefits. This report provides a first-of-its-kind assessment for India on the sector-wise potential of hydrogen, helping policymakers and businesses plan better for a low carbon future.

Based on our analysis, we conclude that green hydrogen (produced from renewable electricity) has huge potential in India's energy transition. In transport, this can be used to fuel longer-range vehicles and heavier-duty trucks, in industry largely as a chemical feedstock, and in the power sector, to provide longer-term energy storage.

As with other clean energy technologies, the falling cost of hydrogen will drive its uptake, with initial scale-up being driven by collaborations between progressive public and private players. And the possibility of the economic viability of hydrogen as a fuel or a feedstock in different applications at different prices provides an opportunity to grow this market, reduce hydrogen prices, and then grow the market again. India has an opportunity to grow an economically competitive low carbon hydrogen sector, reducing energy imports, whilst drastically reducing emissions. At TERI, we look forward to working with partners to accelerate this transition.

A handwritten signature in blue ink, which appears to read "Ajay Mathur". The signature is fluid and cursive, with a horizontal line underneath.

Dr Ajay Mathur

Director General, TERI

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ABBREVIATIONS

ATR	– Auto-Thermal Reforming
BF-BOF	– Blast-Furnace – Basic Oxygen Furnace
CCS	– Carbon Capture and Storage
CCUS	– Carbon Capture, Use and Storage
CF	– Complex Fertilizer
CO ₂	– Carbon Dioxide
CNR	– Catalytic Naphtha Reformer
CUF	– Capacity Utilization Factor
DAP	– Di-Ammonium Phosphate
DRI	– Direct Reduced Iron
EAF	– Electric Arc Furnace
EV	– Electric Vehicle
H ₂	– Hydrogen
KM	– Kilometres
Ktpa	– Kilo tonnes per annum
LCOE	– Levelized Cost of Electricity
LCOH	– Levelized Cost of Hydrogen
LOHCs	- Liquid Organic Hydrogen Carriers
LNG	– Liquefied Natural Gas
Mt	– Million tonnes
Mtpa	– Million tonnes per annum
NG	– Natural Gas
PEM	– Proton Exchange Membrane
RE	– Renewable Energy
RTC	– Round-the-Clock (renewables)
SMR	– Steam Methane Reformation
SOE	– Solid Oxide Electrolysis
SR-BOF	– Smelting Reduction – Basic Oxygen Furnace
TCO	– Total Cost of Ownership
VRE	– Variable Renewable Energy

1

EXECUTIVE SUMMARY

H₂
Hydrogen

Harnessing the hype on hydrogen

Hydrogen has long been the ‘fuel of the future’ but has to-date never quite made it as a major player in the energy system. Today, a number of key developments suggest that the time for a substantial role for hydrogen in the energy system has come. First, concern about global climate change is increasing, and it is becoming clear that decarbonization of the energy system necessitates new low carbon fuels and chemical feedstocks. Second, technology innovation in electrolyzers and electricity generation from zero-carbon renewables is making the prospect of abundant low carbon hydrogen realistic.

However, it is important to put this hype in perspective. To be deployed at scale, hydrogen will need to compete with incumbent fossil fuels and emerging low carbon alternatives, such as battery electric vehicles. Although cheap and abundant, there will be competing demands for low carbon electricity and the production of hydrogen from electrolysis is an extremely electro-intensive process. Moreover, the use of hydrogen in end-uses is not always the most efficient solution, with direct electrification being more efficient in many applications. Finally, the specifics of hydrogen deployment will depend on country context. Hydrogen value chains may look quite different in a context of abundant and consistent zero-carbon hydroelectricity, like Scandinavia, versus a context of abundant but variable solar electricity like India.

For this reason, it is necessary to assess the potential role of hydrogen from a systems perspective, considering all potential end-uses, production routes, and value-chain configurations. This report represents a first-of-its-kind comprehensive assessment for the Indian context.

An emerging virtuous circle for hydrogen deployment

Historically, the deployment of new energy technologies has not been linear. Mass deployment of a technology typically requires technological innovation in the technology itself, as well as in a host of enabling technologies within the broad value chain. For example, while the principle of electric incandescent lighting was demonstrated in the early 19th century, its mass deployment would await multiple enabling innovations in electricity generation and distribution in the last decades of the 19th century.

Today, hydrogen faces a similar situation, whereby numerous technology developments are coming together to enable the successful penetration of hydrogen in the energy system. These include:

- Growing demand in numerous end-use sectors like industry.
- Supply-side innovation in production technologies, notably electrolyzers and renewables.
- Enabling technological developments, for example, the development of high renewables power systems creating ‘technology problems’ which hydrogen can help to solve (notably excess renewables generation, need for long-term electricity storage).
- Growing policy interest in driving deep decarbonization of energy systems, which will require chemical energy carriers like hydrogen, and in capturing the industrial benefits of hydrogen.

These factors are beginning to drive an emerging virtuous circle for hydrogen deployment in the energy systems of several major economies. It is important that India seizes on this emerging virtuous circle as hydrogen could be a crucial tool for a low-emissions, cost-effective, and less import-intensive energy sector for India.

Hydrogen demand could increase 5-fold by 2050, with use in industry being the major driver

Hydrogen demand could increase by at least 5-fold by 2050, continuing to grow in the second half of the century. Demand for hydrogen today is at around 6 Mt per annum, coming solely from industry sectors, such as fertilizers and refineries. This can increase to around 28 Mt by 2050, driven by cost reductions in key technologies, as well as the growing imperative to decarbonize the energy system. Demand will continue to be largely focused in industry sectors, either expanding in existing sectors, such as fertilizers and refineries, or growing into new sectors, such as steel. Hydrogen will play some role in the transport sector in heavy-duty and long-distance segments, and a minor role in the power sector as a long-term storage vector. Beyond 2050, we can expect demand for green hydrogen to continue to grow, particularly in the steel and road transport sectors, as well as in shipping and aviation. Reaching a net-zero target by 2060 could require around 40 Mt of green hydrogen, a 7-fold increase over today.

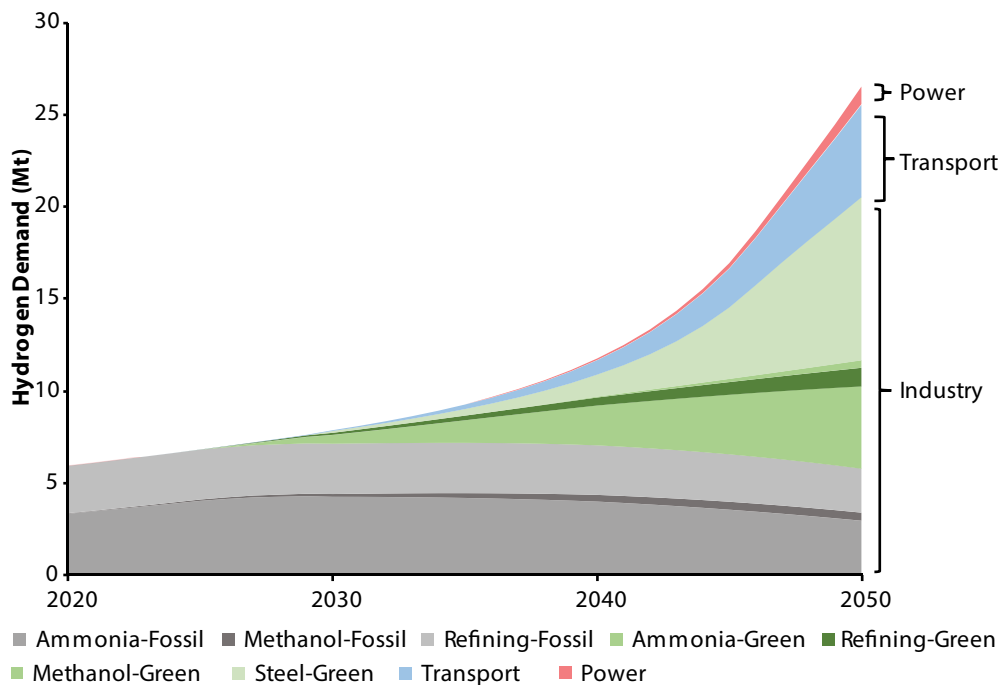


Figure 1: Hydrogen demand projection in the Low-Carbon scenario, 2020-2050

Source: TERI analysis

By 2030, costs of hydrogen from renewables will fall more than 50% and will start to compete with hydrogen produced from fossil fuels

As of today, essentially all of the hydrogen consumed in India comes from fossil fuels. However, by 2050, nearly 80% of India's hydrogen is projected to be 'green' – produced by renewable electricity and electrolysis. Based on a comprehensive assessment of possible production routes conducted in this report, it is clear that green hydrogen will become the most competitive route for hydrogen production by around 2030. This is driven by dramatic cost declines in key production technologies such as electrolyzers and solar PV. For example, the

cost of alkaline electrolyzers is projected to drop from around Rs. 6.3 Cr/MW today to around Rs. 2.8 Cr/MW by 2030. The decline in electrolyser costs will be partly driven by large-scale deployment in India and globally, by a virtuous circle between falling costs and strengthening policy to promote hydrogen. Improving efficiencies of electrolyzers, as well as increasing load factors of solar plants, will also play an important role in driving the costs of green hydrogen below Rs.150/kg by 2030 (\$2/kg) – versus Rs. 300–440/kg (\$4–6/kg) as of today. At this price, green hydrogen starts to compete with hydrogen produced from natural gas allowing it to make inroads into various end-use segments. India’s lack of domestic natural gas supply and high cost of imports make green hydrogen competitive sooner than in other parts of the world.

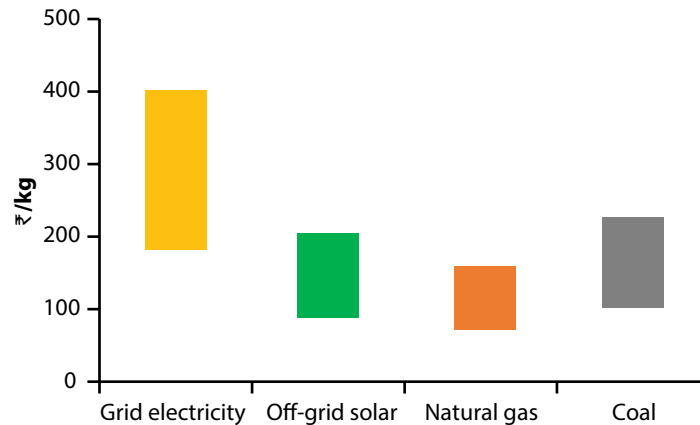


Figure 2: Levelized costs of hydrogen from different sources, 2030 range

Source: TERI analysis based on (IEA, 2019; BEIS, 2018; BNEF, 2020)

Given the scale of the prospective market, India should be proactive in manufacturing electrolyzers to produce green hydrogen

The pace of developments in hydrogen technologies is accelerating, driven by growing interest from governments and businesses around the world looking to drastically reduce emissions from their energy systems, whilst maximizing the use of domestic resources. Several leaders are emerging in this sector, including Japan, the European Union, and China. A window of opportunity still remains for India to capture large parts of this market, using the advantage of a large domestic market, competitiveness of green hydrogen, and low-cost labour. Policies should therefore be oriented to incentivize domestic manufacturing of electrolyzers, in line with the Government of India’s ‘Make in India’ programme. The government should set targets for electrolyser deployment by 2030 and facilitate companies to establish electrolyser manufacturing facilities in India.

Driven by a range of factors, the deployment of hydrogen in different sectors will occur on different timeframes and for different reasons

The term ‘hydrogen economy’ is a misnomer, given that hydrogen is not a panacea for the challenge of energy transition, and will not be suitable for use in all areas of the energy system. Hydrogen’s suitability depends on the specific characteristics of each sub-sector, notably on the need for energy-dense fuels (long-duty transport and long-term electricity storage in power); the need for hydrogen as a feedstock and fuel (ammonia, steel,

methanol); or the need for high grade process heat, for example in industry. Importantly, hydrogen will have to compete with other low carbon technologies, notably direct electrification through for example, battery electric vehicles. Thus, it is important to provide a detailed analysis for each sub-sector, as we do in this report. Table 1 provides an overview of the key findings of this analysis, which are elaborated in the following paragraphs.

Table 1: The role of hydrogen across key sectors

Sector	Use-Case	2020S	2030S	2040S
Transport	Light-duty passenger and freight transport	BEVs competitive with both FCEVs and ICEs	BEVs competitive with both FCEVs and ICEs	BEVs competitive with both FCEVs and ICEs.
	Short-distance, regular-route heavy-duty transport	BEVs becoming competitive with ICEs. FCEVs not competitive.	BEVs competitive with both FCEVs and ICEs.	BEVs competitive with both FCEVs and ICEs.
	Very long-distance heavy-duty freight transport	ICEs competitive.	FCEVs and BEVs becoming competitive with ICE.	FCEVs likely to be competitive with ICE. BEVs partly competitive.
Industry	Ammonia production	Fossil fuels competitive. H ₂ becoming competitive.	H ₂ competitive (ammonia and refineries) and partly competitive (steel).	H ₂ from renewables competitive.
	Steel production			
	Refineries hydrogen demand			
	Methanol production	Fossil fuels competitive.	Fossil fuels competitive. H ₂ partially competitive.	Fossil fuels competitive. H ₂ partially competitive.
	Industrial heat	Fossil fuels competitive. Direct electrification partly competitive.	Fossil fuels competitive. Electrification increasingly competitive.	Fossil fuels likely to be competitive. H ₂ and direct electrification may be partly competitive.
Electricity storage	Short-term (daily) storage	Li-ion batteries competitive.	Li-ion batteries competitive.	Li-ion batteries competitive.
	Short-term (weekly/monthly/seasonal) storage	Long-term balancing from fossil and hydro. Long-term storage needs minimal.	H ₂ becoming competitive but minimal need as wind and solar still below 60-80%.	H ₂ competitive. Long-term storage required in a high wind and solar system.

Legend: Brown = fossil fuels dominate. Yellow = direct electrification without using H₂ as an energy vector, e.g. battery electric vehicles or li-ion batteries in electricity storage. Blue = hydrogen. Green = mixed paradigm with several technologies including hydrogen.

Source: TERI analysis.

Note: This table only covers the use cases assessed in this report and is not exhaustive.

In transport, battery electric vehicles will be competitive across all segments, limiting the role of hydrogen to long-distance and heavy-duty applications

Over the past decade, we have experienced extremely rapid cost reductions in battery technologies, alongside significant improvements in performance. This has made Battery Electric Vehicles (BEVs) lower cost, with greater range and faster recharging times, making them more attractive to consumers across a growing number of segments. Hydrogen Fuel Cell Electric Vehicles (FCEVs) must compete with the ever-improving BEV technologies to have an impact on transport decarbonization. Based on our analysis, from the medium-term, BEVs will dominate most of the smaller, shorter-range passenger vehicles, including two-, three-, and four- wheelers, as well as city buses and last-mile freight. However, FCEVs could remain competitive in longer-distance, heavier-weight vehicle segments, such as heavy-duty trucking. Even in these heavy-duty segments, the eventual winner of the competition between BEVs and FCEVs is not yet clear, as technologies are progressing rapidly.

In industry, steel and ammonia will drive growth in hydrogen demand, followed by refineries and methanol

Industry is the main consumer of hydrogen in India, and this will remain the case out to 2050, with industry making up 80% of total demand in our **Low Carbon** scenario (Figure 1). Today, this is mainly driven by ammonia production and refineries, both of which will increase. According to the analysis of this report, ammonia produced using green hydrogen from dedicated renewables paired with storage could start to compete with natural gas-based ammonia by 2030. Likewise, by the 2030s, steel production based on green hydrogen is projected to be competitive with steel from the traditional fossil fuel routes. Indeed, because of the size of the sector, steel is the main driver of green hydrogen demand in our **Low Carbon** scenario, using hydrogen as a reducing agent to replace coal. With a concerted policy push, it may be possible to foster a domestic methanol industry based on green hydrogen, although this would have to compete with lower cost coal-to-methanol. Although refinery output declines in our **Low Carbon** scenario as transport fuel demand peaks and begins to decline by 2050, green hydrogen could compete with fossil-based hydrogen in India's large refinery sector by 2030. Although further analysis is needed, it is unlikely that hydrogen will compete in industrial heat applications – India should actively explore heat electrification technologies, wherever feasible.

In power, hydrogen could be a cost-effective way of providing inter-seasonal storage in a high variable renewable electricity system from 2040

As India's electricity grid decarbonizes further via the integration of growing shares of wind and solar, more electricity storage will be required to help manage the variability of renewables. Improvements in battery technologies mean that they are already able to provide cost-effective short-term storage to manage intra-day variability. However, as the grid reaches higher and higher shares of variable renewables, there will be fewer coal-fired plants that are able to manage the longer periods of demand and supply variation, such as low wind output during the winter months. As a result, hydrogen could play a role as a long-term storage vector, absorbing excess electricity during certain periods of the year, to be used again at times of sustained low renewable output. This only becomes a necessary option of managing grid variability at high penetrations of variable renewables in

total generation, i.e. above 60–80% of total generation. India is unlikely to reach this level of variable renewables penetration until around 2040.

Hydrogen production from renewables is an energy-intensive process, and direct electrification should be preferred wherever possible

As well as the inherent suitability and competitiveness of hydrogen in different sub-sectors, it is important for policymakers to consider hydrogen deployment from a system-wide perspective. Given the energy-intensive processes required to produce hydrogen, it should be targeted in sectors where direct electrification is not possible. For example, producing 1 kg of hydrogen requires 50 kWh of electricity, based on electrolyser efficiency of 70%, resulting in an energy loss of around 30%. There is then a further energy loss if this hydrogen is stored and converted back to electricity, as is the case for transport and power applications. A corollary of these conversion losses is that the CO₂ intensity of electrolytic hydrogen production is higher than that of the input fuel, electricity. This means that for electrolytic hydrogen to be competitive with fossil fuels, for example in transport, the input electricity must be very low emissions. Hydrogen deployment should thus be prioritized in sectors where no alternatives exist, and its production must be based largely on zero-carbon electricity for net emissions reductions to be achieved.

Industrial clusters are an attractive model for the early development of hydrogen infrastructure

Based on a detailed spatial modelling of India's main industrial clusters, which includes their access to nearby renewable resources, we show that low-cost and reliable green hydrogen production is possible based largely on variable wind and solar. This includes an analysis of a cluster in Gujarat, where we find a concentration of chemical and petrochemical facilities, which can produce hydrogen at \$2/kg by 2030. The analysis also looks at an eastern state, Odisha, with a concentration of steel plants, where hydrogen production costs are slightly higher due to lower quality renewables resources nearby. This analysis also highlights the importance of flexible electrolysers and low-cost hydrogen storage to ensure that a near-constant level of hydrogen demand can be met. Finally, whilst independent hydrogen clusters look attractive, it will still be important for such systems to be connected to the electricity grid to allow export of excess electricity or use grid electricity as a last resort, when needed.

Scaling up the use of domestically produced hydrogen can significantly reduce energy imports

India currently imports 85% of its oil, 50% of its natural gas, and 30% of its coal. This comes at a significant expense, exposing India to the frequent price fluctuations of international energy markets. Domestic production of hydrogen from renewable electricity will significantly reduce energy imports, whilst supporting a domestic energy industry. This improves India's energy security, thereby reducing commodity price uncertainty for major industries. By 2050, annual energy imports could be reduced by around 120 Mtoe (around 20% of today's final consumption), reducing import costs by around Rs.150,000 Cr (\$20bn) each year.

To accelerate the adoption of hydrogen technologies in India, a step-change in government policy and business actions is required

To achieve the ambitious vision set out in this report, a step-change in government policy and business actions will be required. This includes greater cross-sectoral coordination within the government, to help realize the economy-wide benefits and interactions of hydrogen technologies. There must also be a shift from early-stage R&D programmes towards later-stage commercialization support to help bridge the ‘valley of death’. To ensure that low carbon hydrogen is favoured over high emission alternatives, an emissions penalty could be introduced at some stage, either in the form of more stringent regulations, or a carbon tax. To support the demand for green products made using green hydrogen, green product standards should also be introduced. Finally, to support these government-led initiatives, the private sector should target their activity towards competitive projects, while partnering with international technology providers wherever necessary.

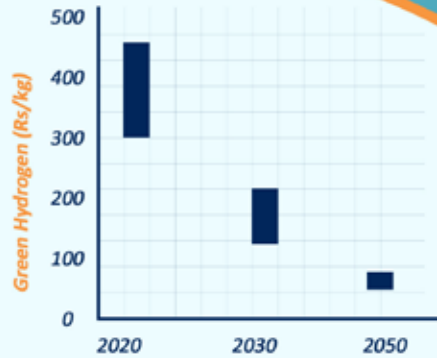
Potential Role of Hydrogen in India:

A pathway for scaling-up low carbon hydrogen across the economy

HYDROGEN DEMAND SET TO INCREASE FIVE-FOLD BY 2050

Demand for hydrogen today is around 6 Mt per annum and may increase to approximately 28 Mt by 2050.

5X



GREEN HYDROGEN WILL START TO COMPETE WITH FOSSIL-FUEL DERIVED HYDROGEN BY 2030, driven by

- Cost reductions in electrolyzers and renewable electricity
- Improving technology efficiencies
- Increasing load factors of solar plants



HYDROGEN NEEDS TO BE TARGETED IN SECTORS WHERE DIRECT ELECTRIFICATION IS NOT POSSIBLE



Transport

Potential segments: long-distance buses and heavy-duty trucks - competitive by 2030.



Industry

Potential sectors: Steel, Ammonia, Refineries and Methanol - competitive by 2030.



Power

Potential for providing inter-seasonal storage by around 2040.

LOCATIONAL FACTORS WILL PLAY AN IMPORTANT ROLE IN DETERMINING WHERE H₂ TECHNOLOGIES ARE DEPLOYED.

INDIA NEEDS TO BE PROACTIVE IN DEVELOPING A DOMESTIC ELECTROLYSER INDUSTRY. POTENTIAL MANUFACTURING OF 150-200 GW OF ELECTROLYSERS BY 2050.

BASED ON LONG-TERM FUEL PRICES, INCREASED USE OF HYDROGEN COULD REDUCE COSTS OF IMPORTS BY JUST UNDER \$20BN A YEAR BY 2050.



MAKE IN INDIA



GOVERNMENT AND INDUSTRY ACTIONS

Government

- Support for R&D, pilots and demonstration
- Green product standards
- Cross-cutting coordination to target resources
- Emissions penalties

Industry

- International collaborations
- Coordinated R&D activity
- Creation of industry clusters



2

INTRODUCTION



Hydrogen has the potential to play an important cross-cutting role in a future low carbon economy, with applications across the industrial, transport and power sectors. There has been a growing appreciation that full electrification of our current energy systems could be prohibitively expensive and technologically challenging, given the important storage, flexibility, chemical, and heating attributes of current fossil fuels. To that end, low carbon hydrogen could mimic these attributes without the associated emissions, providing significant value across sectors. To date, analyses of the role of hydrogen in India's economy have tended to assess its value within single sectors, as opposed to taking the whole systems approach adopted in this report.

Hydrogen is the most abundant element in our universe, although most hydrogen on Earth exists in molecular compounds, such as water (H₂O) or natural gas (CH₄). Extracting pure hydrogen from these compounds requires energy-intensive processes, such as reforming or electrolysis. Once extracted, hydrogen can be combusted or reacted in a fuel cell to produce energy. It also provides a valuable building block for several chemicals, which are used widely in industries such as textiles, pharmaceuticals, and plastics.

Importantly for the energy system, as with other gases, hydrogen can be stored in large quantities, over long periods of time. Also, hydrogen produces zero carbon emissions at the point of use, making it potentially valuable as we transition to a low carbon economy.

Whilst hydrogen has many useful attributes, it is also highly flammable and thus potentially dangerous to handle. As a result, there are some negative public perceptions of hydrogen, most famously regarding the Hindenburg Disaster of 1937; but also, more recently, in September 2019, regarding an explosion at a hydrogen refuelling station in Santa Clara, California. Despite the incidents, there are decades of experience in the safe use of hydrogen in the refining and chemical industry. Finally, whilst hydrogen has a high energy density by weight, it has a low volumetric energy density, meaning costs of storage can be high if large facilities or liquefaction are required. High cost of hydrogen fuel is also a limiting factor.

Historically, hydrogen has been used in India, mainly as an industrial feedstock in the creation of ammonia-based fertilizers. Hydrogen derived from both fossil fuels and electricity has been used for many years in India, with the country's first large-scale alkaline electrolyser being deployed at Nangal in Punjab from 1962. It was later closed down as a result of increasing demands for electricity elsewhere in the economy, and replaced by hydrogen production from natural gas.

The Ministry of New and Renewable Energy (MNRE) developed a Hydrogen and Fuel Cell Road Map, published in 2006 (MNRE, 2006). In 2016, MNRE published a further report, which laid out more up-to-date plans for the Government's ambitions for hydrogen (MNRE, 2016). This report lays out a comprehensive plan for increasing R&D activity in India across a number of programme areas, with the 2016 report showing ambitious timelines for research activities out to 2022. Given the nascent stage of most hydrogen-based technologies, MNRE's activities have mainly focused on increased research activity, as opposed to wide-scale deployment. Most recently, the Government of India is in the process of preparing a Hydrogen Mission, with support from the MNRE and NITI Aayog, which is expected to be unveiled in 2021.

Within industry, several organizations have convened the Hydrogen Association of India. The organization has support from across a range of sectors, including chemical, petrochemical, transport, and power sector companies. Within academia, a large number of universities are engaged in technical research, including public and private bodies.

Hydrogen technologies have gone through several periods of hype over the past few decades, initially stimulated by the oil crisis in 1973 (Figure 3). This is when countries started exploring alternative sources of energy to reduce import dependency. More recently, there was a drive towards hydrogen technologies during the 2000s aimed at rapidly expanding their role in the transportation sector. However, the high costs of hydrogen technologies, along with a lack of sustained policy support meant that there was no major uptake at this time. What then followed

in many parts of the world could be described as a ‘trough of disillusionment’, as governments and businesses discounted hydrogen on the basis of past failures. So why is this time different?

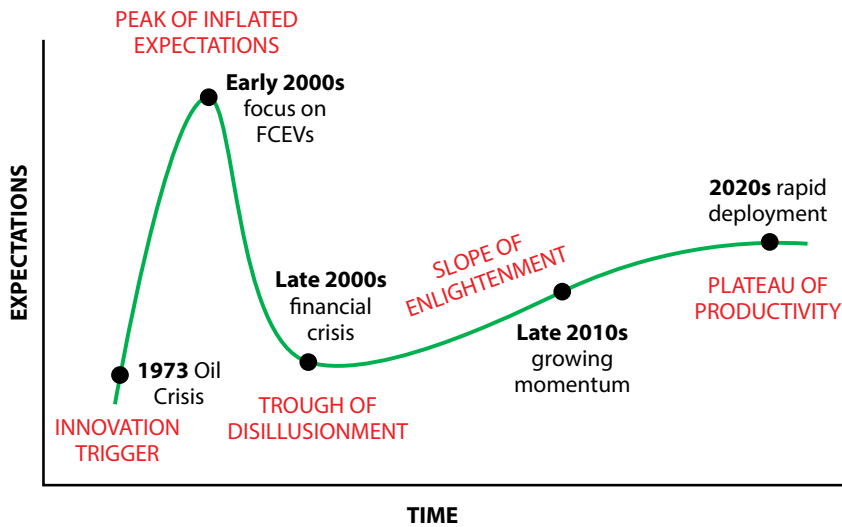


Figure 3: The hydrogen hype cycle

Source: TERI

Based on our analysis, we see three main factors driving a change in this situation for the 2020s. This includes continued rapid cost reductions of renewable electricity, cost reductions and performance improvements of electrolysers, and significant action on tackling climate change.

To illustrate the uncertainty in the future potential of hydrogen in India, as well as exploring potential drivers to accelerate the transition, we present two scenarios throughout this report. Our **Baseline** scenario sets out how we expect the energy system to develop based on current economic and policy trends. Our **Low Carbon** scenario presents a version of the world where policies are put in place to dramatically accelerate the energy transition, which includes earlier and faster adoption of hydrogen technologies (Figure 4). This scenario is broadly aligned with the Indian energy system reaching net-zero emissions by 2060, or shortly thereafter.

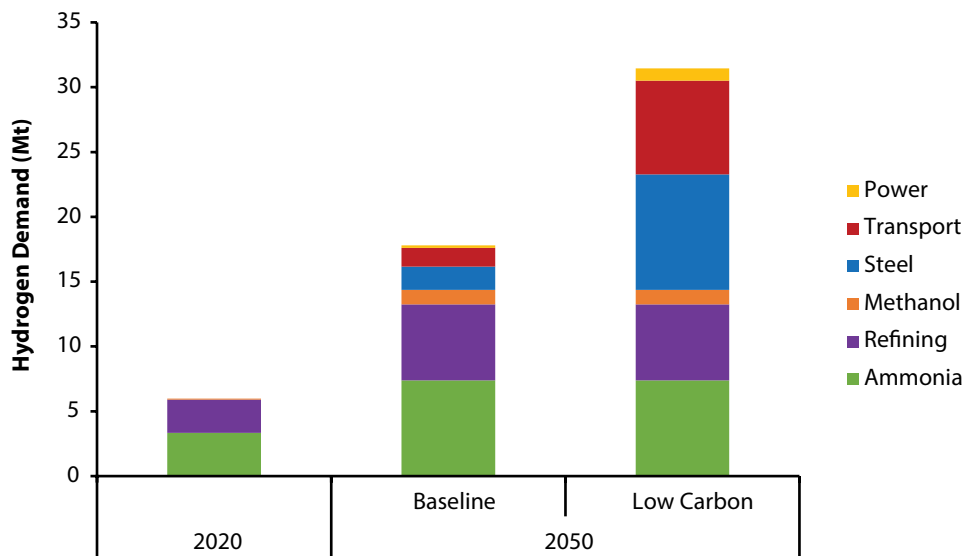


Figure 4: Baseline and Low Carbon scenarios, 2020 and 2050

Source: TERI analysis

Note: Demand projections exclude potential use of hydrogen in shipping, aviation, and petrochemicals, which are not covered in this report.

The global momentum driving forward hydrogen technologies will result in significant uptake even in the **Baseline** scenario, although the domestic benefits to the Indian economy will be limited. Under the **Low Carbon** scenario, we expect a multitude of domestic policies to accelerate the transition, including greater R&D support, demonstration projects, international finance, emissions penalties, green product regulations, public-private partnerships, and manufacturing support. These would contribute to more hydrogen being used in certain sectors, particularly steel and transport, with greater benefits to the Indian economy as a result of proactive policy.

The report sets out the current status of hydrogen technologies in Section 3, outlining cost reduction trajectories out to 2050. In Section 4, we assess the role of hydrogen in different transport segments, including two-, three-, and four- wheelers, as well as buses and heavy-duty trucks. In Section 5, we assess the role of hydrogen in key industrial sectors, covering ammonia, methanol, refineries, steel, caustic soda, and industrial heat. Section 6 sets out the impact of growing hydrogen demand on the power sector, including total electricity demand scenarios, as well as its potential role as a seasonal storage solution. Section 7 brings together a series of cross-sectoral analyses that highlights the spatial aspects of hydrogen infrastructure deployment, the challenges and opportunities of electrolyser manufacture, and the total energy supply impact under our scenarios. Section 8 concludes this analysis with key messages and recommendations for policies that can accelerate the energy transition through greater use of low carbon hydrogen.

3

HYDROGEN TECHNOLOGIES



Key messages

- Most hydrogen in India today is produced via steam methane reforming and mainly used in the fertilizer and refinery sectors.
- India is well-suited to green hydrogen production, given low renewable electricity prices from renewable energy sources and high imported gas prices.
- Costs of green hydrogen need to fall below Rs110/kg (\$1.50/kg) to out-compete hydrogen produced using natural gas (at \$8/mmbtu delivered cost).
- For most applications within India, transporting hydrogen as a gas via pipeline is most cost-effective.
- Initial surveys suggest that India has limited geological storage options, and may need to use much more expensive steel tank storage.

3.1 Production

In India, most hydrogen is produced using natural gas for use in the refinery and fertilizer industries. Historically, a greater proportion of hydrogen was produced using naphtha, but this has declined primarily with the shift to natural gas in the fertilizer sector. Coal gasification to produce hydrogen has also been used in the past but it did not really pick up. However, it has again received greater interest in recent years to help lower energy costs and reduce energy imports.

Hydrogen also used to be produced using water electrolysis on a small scale in India, although this has declined over the years as demand for electricity has increased, alongside the availability of natural gas. A small amount of hydrogen continues to be produced from water electrolysis for smaller, on-site applications, or where it is produced as a by-product in the chlor-alkali industry.

In this section, we explore three broad groups of hydrogen production technologies, which are able to scale-up in the near to medium term. This includes electrolysis (alkaline and proton exchange membrane [PEM] technologies), methane reformation (steam methane reformation –[SMR] and auto-thermal reformation [ATR]), and coal gasification (above-ground and below-ground).

Given we are primarily interested in how hydrogen can reduce emissions from the Indian energy system, we assess the impact of using renewable electricity (100% zero carbon) with electrolyzers, as well as the effect of carbon capture, usage and storage (CCUS) infrastructure for methane reformation and coal gasification routes. These routes are typically referred to as green and blue hydrogen (Figure 6).

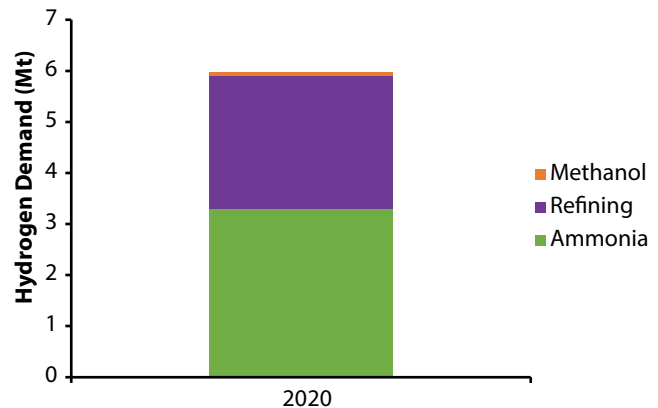


Figure 5: Hydrogen demand by sector, 2020

Source: TERI analysis based on (Ministry of Chemicals and Fertilizers, 2020)

Beyond these leading production routes, this section will also cover a few emerging technologies that could also play some role in supporting growing hydrogen demand in India. This includes methane pyrolysis (so-called ‘turquoise’ hydrogen), biomass gasification, anaerobic digestion, and photolysis.

3.1.1 Electrolysis

3.1.1.1 Technology Description

Water electrolysis is an electrochemical process that splits water into hydrogen and oxygen using electricity. Globally, only 4% of hydrogen is produced through this process, with most of this being by-product hydrogen from the chlor-alkali industry. If the electricity comes from renewables, then hydrogen from electrolysis has the potential to be zero carbon.

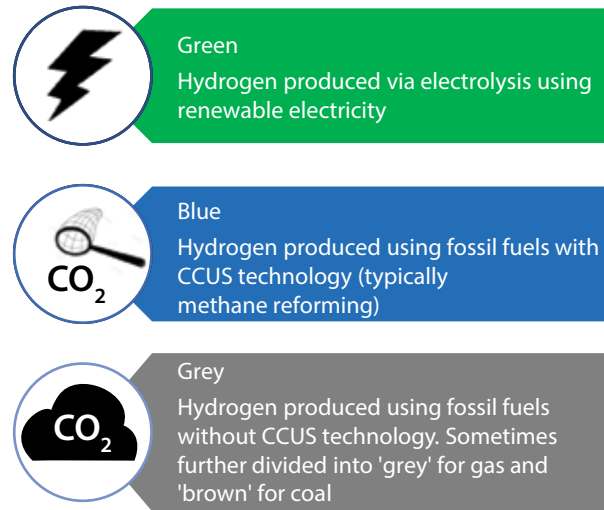


Figure 6: Hydrogen production routes

Source: TERI

We provide an overview of three main electrolysis technologies, including – alkaline, proton exchange membrane (PEM), and solid oxide electrolysis (SOE). At present, only alkaline and PEM electrolyzers are commercially available (IEA, 2019), and hence these technologies will be the focus of the later techno-economic analysis (Table 2).

Table 2: Overview of electrolyser technologies, 2020

Metric	Unit	Alkaline	PEM	SOE
Cost		Moderate	Moderate / High	High
Lifetime	years	20–30	10–20	10–20
TRL		9	8	7
Footprint	m ² /kW	0.095	0.048	0.095
Water requirement	Litre/kWh	9	9	9
Efficiency (LHV)		63-70%	56-60%	74-81%
Start-up time	min	>30 min, medium	<30 min, low	>30 min, very high

Source: TERI analysis based on (IEA, 2019; BEIS, 2018; IRENA, 2019)

Note: TRL = Technology Readiness Level. Lifetime refers to technical lifetime of the electrolyser as a whole and not the stack.

Alkaline electrolysis is the most mature technology, having been used in the fertilizer and chlorine industries since the 1920s. The process requires approximately 6 kWh of electricity to produce 1 Nm³ of hydrogen per hour, equivalent to around 50 kWh of electricity per kg of hydrogen. Currently, efficiencies are around 65% but are expected to increase near 80% in the longer term, as deployment ramps up (IEA, 2019).

Alkaline electrolyzers have relatively low capital costs compared to PEM electrolysis and fewer rare raw materials are required. Nonetheless, there are a few limitations of current alkaline electrolyser technology, namely, limited operational flexibility (although this is improving), larger area footprint, and low output pressure. Whilst R&D

activity for alkaline electrolyzers is focused on addressing these limitations, including funding for augmented alkaline technologies, PEM electrolyzers can provide an alternative if these issues present a problem for the user.

PEM electrolyzers have several advantages over alkaline electrolyzers, including the ability to ramp output up and down rapidly, work above capacity for short periods, occupy a smaller footprint, and deliver hydrogen at a higher output pressure. Nonetheless, there is a trade-off for these benefits, including lower average efficiencies of operation, as well as higher capital costs due to the requirement of more expensive catalyst materials. PEM electrolyzers currently have an electrical efficiency of approximately 58%, which is expected to increase to over 70% in the longer term (IEA, 2019).

Balance-of-plant (BOP) costs are dominated by items such as transformers, rectifiers, and control systems, which contribute significantly to total installed costs. The BOP also includes water purification, hydrogen dryer, and a hydrogen purifier (if needed). The estimated percentage of these costs varies considerably across suppliers and is due to the uncertainty in how the supplier draws the line between the electrolyzer and the BOP.

SOE technology is not commercially available and is the least mature electrolyzer technology discussed in this report. The process has relatively low material costs, although these materials face rapid degradation due to high operating temperatures (900–1000°C), which results in high overall costs. SOE electrolyzers have the highest operating efficiencies of the different technologies covered within the scope of this report, rising from around 78% today up to 90% in the longer term. It is also possible to make use of waste heat to improve overall efficiencies (BEIS, 2018). The main obstacle to the industrial applications of SOEs is the limited long-term stability of electrolysis cells, with R&D efforts currently focused on increasing the lifetime of the electrode.

The average capacity of electrolyzers projects has increased from 0.1 MW scale during the 2000s to 1 MW scale in the 2010s. Projects at the 10 MW and 100 MW scale are now being planned in multiple regions around the world. Achieving economies of scale through these projects will help drive down costs, encouraging additional projects to come online. These developments will encourage economies of scale, driving down the costs of electrolyzers. More details on projects outside India are given in Box 1.

Box 1: International electrolyzer projects

Region	Projects	Policy
European Union	<ul style="list-style-type: none"> In the lead in operational, utility-scale projects above 1 MW – most projects in Germany. Pipeline of proposed electrolyzer projects is 27 GW. Most in development stage. Germany – <u>Westküste 100 project</u> <u>600 MW</u> electrolyzer project is being developed by Ørsted and EDF. Netherlands – <u>10 GW NorthH2 project</u> – largest electrolyzer project powered by offshore wind proposed by Shell-led conglomerate. 	<p><u>The Hydrogen Strategy:</u></p> <ul style="list-style-type: none"> Sets out a target of reaching 40 GW hydrogen electrolyzer capacity by 2030. Aspirational target of 40 GW of electrolyzer capacity to be set up outside Europe through an import supply chain. <u>Germany (5 GW), Spain (4 GW), UK (5 GW) and France (6.5 GW), Portugal (2 GW), Italy (5 GW)</u> have committed to various electrolyzer capacity targets respectively, for the production of green hydrogen by 2030.

Region	Projects	Policy
Asia – Japan	<ul style="list-style-type: none"> New Energy and Industrial Technology Development Organisation (NEDO), Toshiba Energy Systems & Solutions corporation, Ohoku Electric Power Co., Inc., and Iwatani Corporation announced the completion of the Fukushima Hydrogen Energy Research Field project - <u>A 10 MW renewable-energy powered hydrogen production unit.</u> 	<ul style="list-style-type: none"> Ministry of Economy, Trade and Industry released a basic <u>hydrogen strategy in 2017.</u> The focus is on promoting in power generation, mobility, industrial process and heat utilization and other areas. The country has set a target of increasing sales of FCVs to <u>800,000 by 2030</u> and aims to <u>increase the number of hydrogen stations to 360 by FY2025.</u>
Asia – Korea		<ul style="list-style-type: none"> Government has laid out plans to transform <u>10% of the country's cities, counties, and towns to hydrogen-powered by 2030</u> and 30% cities by 2040. <u>3 hydrogen-powered cities are to be built by 2022.</u> The cities will use hydrogen as a fuel for cooling, heating, electricity, and transportation. Related infrastructure will include <u>9.9MW fuel cells, 670 hydrogen fuel-cell electric passenger vehicles, and 30 hydrogen buses.</u>
Asia - China	<ul style="list-style-type: none"> Proposed <u>5 GW Beijing Jingneng</u> facility in Inner Mongolia – first gigawatt-scale electrolyser to become fully operational. Will include a solar and onshore wind farm. Energy from these facilities would feed <u>400,000-500,000 tonne of hydrogen per year.</u> 	<ul style="list-style-type: none"> <u>Hebei province approved \$1.2 billion</u> of projects for hydrogen equipment manufacturing, filling stations, fuel cells, and hydrogen production including electrolysis.
Australia	<p>Proposed electrolyser projects of 1 GW or more -</p> <ul style="list-style-type: none"> <u>\$16 billion project - Asian Renewable Energy Hub</u> – will produce 50 TWh of clean electricity using wind and solar energy <u>Murchinson Renewable Hydrogen Project</u> – will develop a large-scale (up to 5,000 MW) combined wind and solar farm to generate low-cost renewable hydrogen. <u>Gladstone Hub</u> – Hydrogen Utility will install an electrolyser plant with a capacity of up to 3 GW and produce up to 5,000 tonne of ammonia. <u>Pacific Solar Hydrogen</u> - Austrom Hydrogen will build a solar farm and battery facility with a capacity of up to 3,600 MW. Potential hydrogen production of 200,000 tonne per year. 	<ul style="list-style-type: none"> Government-funded <u>Clean Energy Finance Corporation (CEFC)</u> has committed up to \$300 million in debt or equity financing to support the development of Australia's hydrogen industry. <u>Australian Renewable Energy Agency (ARENA)</u> will award \$70 million funding for two or more electrolyser projects with a minimum capacity of 5 MW and a preferred capacity of 10 MW or larger. Agreements have been signed with South Korea, Japan to establish an international hydrogen supply chain.

Region	Projects	Policy
United States	<ul style="list-style-type: none"> Mitsubishi is planning to install hydrogen turbines to meet Los Angeles' power demands to support a flexible grid. CF Industries approved a green ammonia project at the company's Donaldsonville Nitrogen Complex to produce approximately 20,000 tonnes of green ammonia per year. 	<ul style="list-style-type: none"> U.S. Department of Energy has committed approximately \$64 million in 2020 for 18 projects as part of its H2@Scale vision for hydrogen production, storage, distribution, and use.
Canada	<ul style="list-style-type: none"> Air-Liquide plans to build the largest PEM electrolyser (20 MW) capacity to produce hydrogen from hydro-power. 	
Chile	<ul style="list-style-type: none"> Engie and Eneax have signed a strategic partnership for feasibility study of their pilot green ammonia production complex project. 	<ul style="list-style-type: none"> Chilean Government unveiled a national strategy to develop green hydrogen industry with objectives to produce world's cheapest hydrogen by 2030, and 5 GW of electrolyser capacity by 2025 (and 25 GW by 2030).
Saudi Arabia	<ul style="list-style-type: none"> The Kingdom of Saudi Arabia, Air Products Inc., ACWA Power, and NEOM have signed an agreement for a hydrogen-based ammonia production facility powered by renewable energy. 	

Leading manufacturers of electrolyser technologies are currently concentrated in Europe, China, Japan, and the US. The major companies in Europe and the US include Nel Hydrogen, ITM Power, Thyssenkrupp, Cummins Inc and Siemens. Companies in Japan include Toshiba, Asahi Kasei, Hitachi, Zosen, Kobelco, Honda, and companies in China include Peric, Ningbo Heli Hydrogen Energy Technology, Tianjin Mainland Hydrogen Equipment, and Suzhou Jing Li Hydrogen Production Equipment (E4tech, 2019). More details on these manufacturers are given in the Annex B.

3.1.1.2 Techno-economic Analysis

We have undertaken a detailed techno-economic assessment for the main commercial electrolyser technologies, namely - alkaline and PEM. We have considered two modes of operation based on the source of electricity input: near constant operation using grid electricity and a more intermittent operation using solar electricity. There are several other potential modes of operation, including adding battery storage to renewables to increase the utilization of the electrolyser, supplying electricity from a hybrid renewables facility (e.g. wind and solar), and oversizing electrolysers and the renewable electricity production to supply gaseous hydrogen storage. These are all explored later in the report.

Table 3 sets out our central assumptions for these electrolyser technologies, covering capital expenditure (Capex), operational expenditure (Opex), efficiency, capacity utilization factor (CUF) dictated by the electricity supply and the cost of electricity.

Table 3: Electrolyser assumptions

Tech / input	Metric	Unit	2020	2030	2050
Alkaline	Capex	Rs/kW	66,600	29,600	14,800
	Opex	% Capex	3	3	3
	Efficiency	%	67	68	75
PEM	Capex	Rs/kW	81,400	48,100	14,800
	Opex	% Capex	2	2	2
	Efficiency	%	58	66	71
Grid electricity	Cost	Rs/MWh	6,290	5,550	4,810
	CUF	%	95	95	95
Solar electricity	Cost	Rs/MWh	2,146	1,628	1,258
	CUF	%	19	26	30

Sources: (IEA, 2019; BEIS, 2018; BNEF, 2020)

Figure 7 shows the levelized cost of hydrogen (LCOH) in Rs/kg from alkaline and PEM electrolysis for both grid and solar electricity modes of operation. Costs of hydrogen from electrolysis today are relatively high, at around Rs 400/kg versus Rs140–180/kg from natural gas reformation. However, as the costs of electricity and electrolyzers fall, the efficiencies of electrolyzers improve, and the average load factor for renewables improves, we can expect costs of green hydrogen to fall to around Rs 150/kg by 2030 and Rs 80/kg by 2050 (equivalent to approximately \$2/kg by 2030 and \$1/kg by 2050).

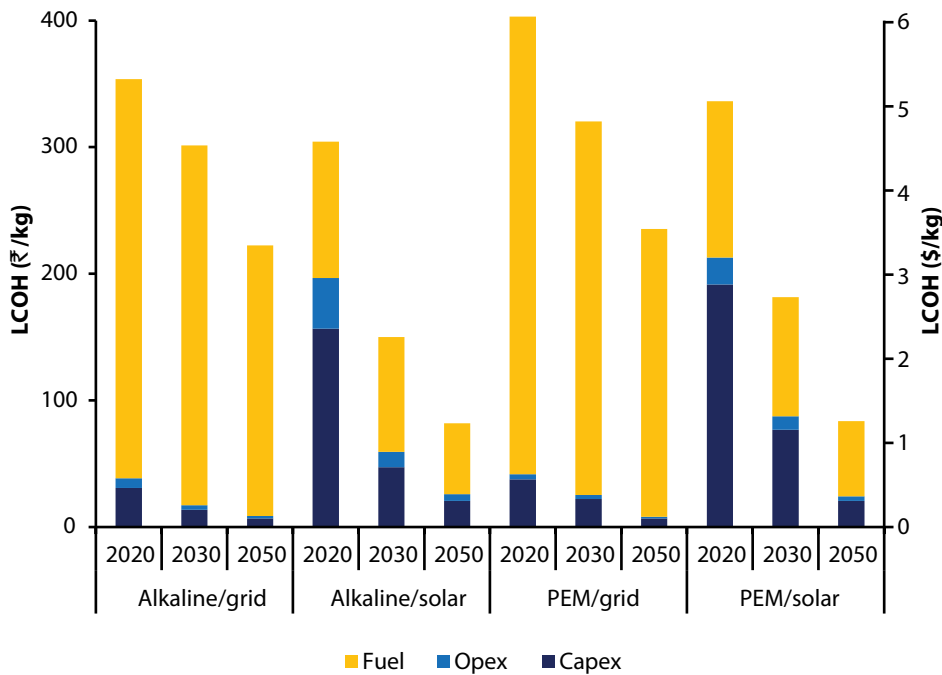


Figure 7: Levelized costs of hydrogen from electrolysis routes, 2020, 2030, 2050

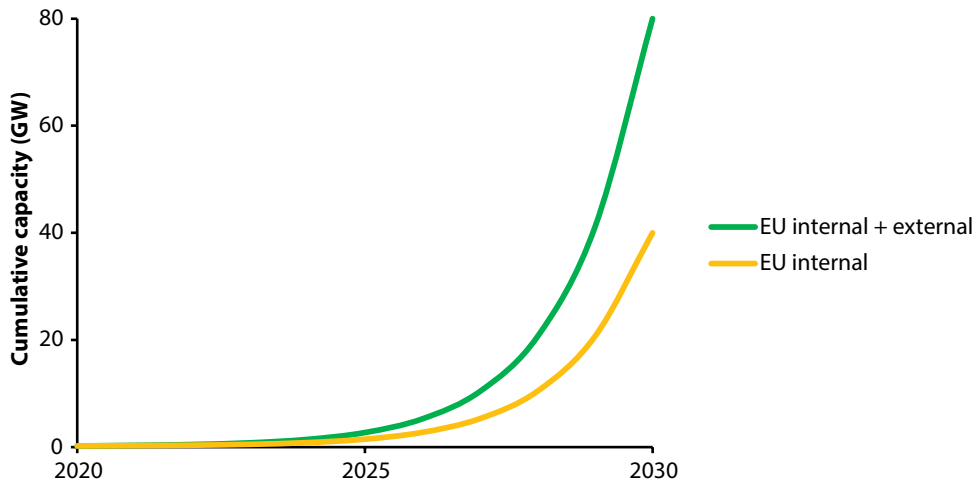
Source: TERI analysis based on (IEA, 2019; BEIS, 2018; BNEF, 2020)

Note: Fuel = electricity

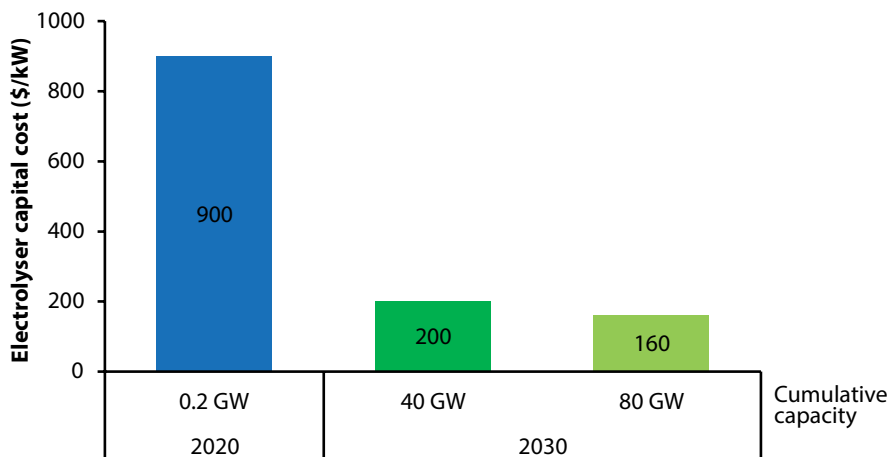
The more cost-effective mode of operation is using renewables instead of grid electricity. This is due to the high costs of grid electricity in India relative to direct procurement of renewables. In addition, as electrolyser capital costs fall, the lower utilization rate of electrolysers driven by variable renewables is less of a concern, as the inverse relationship between utilization rate and per unit costs is weaker with lower capital costs. Another important driver of this cost reduction will be increasing the average CUF of solar plants, which we assume could rise from around 20% today to 30% by 2050. This is expected through a combination of improved operation and maintenance, as well as the introduction of the latest solar technologies, such as dual axis tracking.

Box 2: International electrolyser targets

In early 2020, the European Commission launched the EU Hydrogen Strategy, aimed at accelerating the development and adoption of low carbon hydrogen technologies. The EU set targets of deploying 40 GW of electrolysers by 2030 (EC, 2020). Since the launch of this strategy, an industry initiative called the European Clean Hydrogen Alliance has announced targets for an additional 40 GW to be built outside the EU (EC, 2020).



Assuming a learning rate of 18%, we can estimate the impact of these targets on electrolyser capital costs. It is estimated that the current energy-related electrolyser capacity is around 0.2 GW (other electrolyser capacity is largely for the chlor-alkali sector). Based on these assumptions, electrolyser capital costs would fall to around \$200/kW based on the EU’s targets alone, or to \$160/kW if a larger pipeline of projects is also established outside the EU. This goes some way in supporting the rapid cost reductions that we have previously assumed.



3.1.2 Other Considerations

3.1.2.1 Water Requirements

Electrolysis requires around 9 litres of fresh water to produce one kg of hydrogen (and 8 kg of oxygen). India's entire hydrogen demand with electrolysis would require around 54 million cubic metre today, rising to approximately 270 million cubic metres by 2050. India's total usable water supply is between 700 billion cubic metre and 1,200 billion cubic metre, although this is declining with overuse and climate change (NBR, 2013). Based on this, water requirements for electrolysis would consume at most around 0.05% of India's water supply.

Whilst at an aggregate level, water consumption for electrolysis appears to be a minor issue, it will be important to plan facilities in areas which do not already suffer from water stress. According to the Composite Water Management Index (CWMI) report by NITI Aayog published in 2018, 21 major cities are already reaching zero groundwater levels in 2020 – affecting access to water for 100 million people (NITI Aayog, 2019). By 2030, water demand is projected to be twice the available supply, implying severe scarcity (Down to Earth, 2019). The challenge of salination in the coastal states will also become a growing concern with sea level rise. This has motivated a growing area of research in looking at seawater electrolysis to develop catalysts that can withstand saltwater as an input (The Times of India, 2020). An alternative to this is large-scale desalination of seawater, which has the potential to be relatively low cost at around Rs 52–185/m³ (\$0.7–2.5 per m³) of water, which equates to around a maximum of Rs 1.5/kg of hydrogen (\$0.02/kg) (IEA, 2019).

3.1.2.2. Low Carbon Electricity Requirements

The low carbon electricity requirements for future increases in green hydrogen production will be significant. If 100% of India's 2050 hydrogen demand (in the **Low Carbon** scenario) was to be met through electrolysis, this would require an additional 1,500 TWh of electricity, more than India's entire grid electricity supply today. This would be equivalent to 580–690 GW of solar PV (depending on the CUF), or around 20 times today's installed capacity. When added to the existing challenge of meeting growing electricity demand in other parts of the economy, which would total around 5,000 TWh in 2050, this could limit the pace of green hydrogen rollout. The impact on the electricity sector is explored in detail in Section 6.

3.1.2.3 Raw Material Constraints

Alkaline electrolyzers require approximately 33,333 kg of unalloyed steel, 3,167 kg of nickel and 333 kg of copper per MW scale facility (Koj, Wulf, Schreiber, & Zapp, 2017). To illustrate a maximum potential scenario, if all hydrogen demand was being met by alkaline electrolyzers in 2050, 380 GW of electrolyzers would be required. This would result in 12 Mt of steel, 1.2 Mt of nickel, and 0.12 Mt of copper. For both steel and copper, whilst significant, this would be achievable given India's domestic reserves. For nickel, there is greater uncertainty, particularly in the context of rapid growth in demand for nickel-based batteries for electric vehicles. Efficient recycling of materials should help overcome the challenge but proactive engagement along the supply chain, in particular with mining companies, would be vital.

Box 3: Electrolysis research projects in India

Whilst India has limited electrolysis manufacturing capability, there are many research programmes supported by both public and private funds. A list of activities can be found in the below table.

Institution	Projects
Bhabha Atomic Research Centre, Mumbai	<ul style="list-style-type: none"> • Exploring hydrogen production using – • Alkaline Water Electrolysis (AWE) • PEM • Thermo-chemical splitting of water with Iodine Sulphur process and Cu-Cl processes • High Temperature Steam Electrolysis (HTSE) and Hybrid Sulphur (Hy-S) cycle
CSIR-CECRI, Karakudi	<ul style="list-style-type: none"> • Designing electrodes and electrolytes for hydrogen generation using seawater. This technology has been shared with industry.
The Institute of Chemical Technology, Mumbai	<ul style="list-style-type: none"> • Exploring hydrogen production via sorption enhanced reforming and hybrid bi-functional materials.
University of Lucknow	<ul style="list-style-type: none"> • The chemistry research group at the university is exploring the use of transition metal mixed oxides for AWE and other low-temperature synthesis routes.
Thermax	<ul style="list-style-type: none"> • Exploring the generation of hydrogen via catalytic routes including on-board generation from liquid organic compounds.
ONGC Energy Centre (OEC)	<ul style="list-style-type: none"> • The Centre has patented a new Cu-Cl cycle and demonstrated a closed-loop I-S cycle. • Exploring thermochemical water splitting for hydrogen generation
University consortium–IIT Kanpur, IIT Madras, IIT Jodhpur, BARC Mumbai, etc.	<ul style="list-style-type: none"> • Developing scalable versions of solar hydrogen generation using various technologies. • Electrolysers linked to photovoltaic modules will also be fabricated.
Multiple institutions, ARCI	<ul style="list-style-type: none"> • Projects related to hydrogen generation using methanol are being undertaken.

Source: (Department for Science and Technology, 2020)

3.1.3 Methane Reformation

3.1.3.1 Technology Description

Methane reformation involves the processing of natural gas for the production of hydrogen, with carbon dioxide produced as waste. The main commercially available technology is steam methane reformation (SMR), which accounts for approximately 76% of global hydrogen production (IEA, 2019). Auto-thermal reformation (ATR) is another potentially important technology, which is gaining attention due to its higher efficiency and improved suitability to CCUS technology than SMR.

The SMR process comprises two stages: first, the natural gas is mixed with steam and fed into a tubular catalytic reactor to produce hydrogen and carbon monoxide. Then, the cooled gas is fed into a catalytic converter with

more steam where carbon monoxide is converted into CO₂ and H₂ (Kalamaras & Efstathiou, 2013). Being a mature technology, modern SMR systems are relatively efficient and can be highly optimized to specific applications.

ATR combines the features of SMR alongside a partial oxidation system. The reformer requires no external heat source and no indirect heat exchangers, thus improving the efficiency of operation. However, the process does require pure oxygen, adding slightly to the operating costs. The heat generated through partial oxidation is used to drive the steam reforming reaction (MNRE, 2016). Most of the CO₂ from the process is produced within the reactor itself, making capture far easier, given the single point source (IEA, 2019).

Whilst ATR does have several benefits, SMR is expected to remain the dominant technology in the near term around the world, due to the lifetimes of existing installed capacity. The share of ATR technology will rise rapidly with greater requirements for blue hydrogen. There are also other methane reformation technologies, which are being developed by major companies with blue hydrogen production in mind. Most recently, Shell has developed their Shell Gas Partial (SGP) Oxidization technology, which aims to further increase efficiency and reduce CO₂ emissions by up to 100% (Shell Catalysts & Technology, 2020).

3.1.3.2 Techno-economic Analysis

As the main commercially available technologies, we compare the costs of hydrogen produced through SMR and ATR. We consider two gas price scenarios for both technologies based on the range of imported gas prices for India. Table 4 sets out our central assumptions for these reformation technologies, covering capital expenditure (Capex), operational expenditure (Opex), efficiency, cost addition of CCS infrastructure, and costs of natural gas.

Table 4: Methane reformation assumptions

Tech / Input	Metric	Unit	2020	2030	2050
SMR	Capex	Rs/kW	45,510	39,960	31,080
	Opex	% Capex	5	5	5
	Efficiency	%	74	74	74
	Capture rate	%	70	70	70
ATR	Capex	Rs/kW	55,870	50,320	38,110
	Opex	% Capex	2	2	2
	Efficiency	%	81	81	81
	Capture rate	%	97	97	97
CCS	Capex	increase	+50%/+30%	+50%/+30%	+50%/+30%
	Opex	increase	+100%	+100%	+100%
	Fuel	increase	+10%	+10%	+10%
NG	Price	Rs/mmbtu	592–888	666–962	740–1,036

Sources: (BEIS, 2020; BEIS, 2018; IEA, 2019)

Note: For cost of CCS, left-hand number refers to cost increase for SMR and right-hand for ATR.

Figure 8 shows the levelized costs of hydrogen in Rs/kg from SMR and ATR under the high and low gas price scenarios. We estimate that the cost of hydrogen produced from natural gas without CCS (grey hydrogen) can be achieved at around Rs 130/kg and Rs180/kg in India, depending on the price of the natural gas. In other regions around the world, where natural gas prices are significantly lower, prices of Rs 80/kg and below are possible via this route.

Adding the costs of CCS infrastructure (blue hydrogen) would increase the costs of production by approximately 10–15%. These costs depend on the distance to a CO₂ storage site and the size of the plant (Box 4). ATR can theoretically achieve greater CO₂ reduction more cost-effectively than SMR. CCS for SMR is thought to only be cost-effective at around a 70% capture rate, leaving significant residual emissions. As CCS technology is relatively underexplored in India, there is significant uncertainty in these additional costs, particularly in relation to the storage of the CO₂.

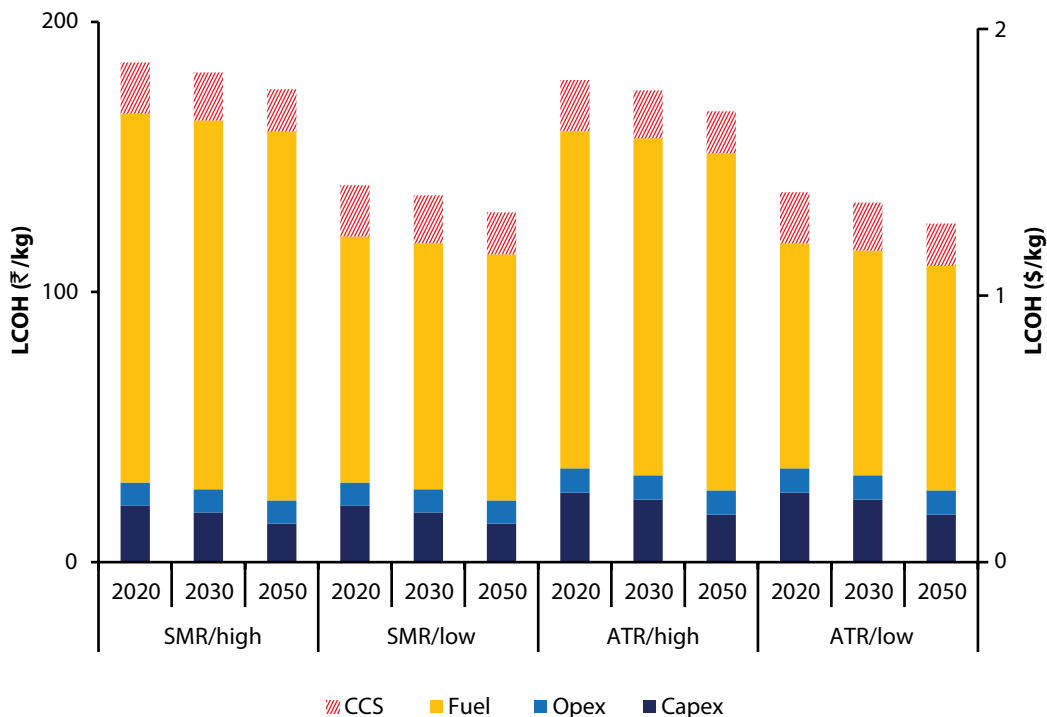


Figure 8: Levelized costs of hydrogen from methane reformation, 2020, 2030, 2050

Source: TERI analysis based on (BEIS, 2018; IEA, 2019; BEIS, 2020)

3.1.4 Other Considerations

3.1.4.1 Natural Gas Price and Availability

The cost of hydrogen production via methane reformation technologies is highly sensitive to the price of natural gas. The price of natural gas in India varies significantly depending on the source, with the greatest divergence between imported and domestic supplies. Today, domestic prices of natural gas are around \$2–3/mmbtu, which are derived by government-approved formula linked to global gas hubs. The government also stipulates which priority sectors will be able to access domestic natural gas, which currently covers city gas distribution (CGD), power, fertilizers, and certain other industrial facilities.

Imported gas prices are currently low at approximately \$6-8/mmbtu for the delivered cost due to the impact of Covid-19, which has suppressed demand. However, this hasn't affected the long-term LNG contracts, which are signed for multi-year periods. Over the longer term, we can expect that spot gas prices will once again return to pre-Covid levels, as demand for natural gas recovers (Royal Dutch Shell, 2020). The longer-term cost range is \$10-12/mmbtu.

3.1.5 Coal Gasification

3.1.5.1 Technology Description

Coal gasification technology is able to produce a range of gaseous chemical feedstock streams, which are then used throughout the chemicals industry, such as for fertilizer production. Approximately 130 coal gasification plants are currently in operation today, with more than 80% in China. The process involves heating coal to very high temperatures, which releases a mixture of carbon monoxide, carbon dioxide, hydrogen, natural gas, and water vapour.

Coal gasification has received greater interest in recent years as a way to displace energy imports for countries with large domestic coal reserves but insufficient oil or natural gas reserves. India fits this description and as such is looking to significantly expand coal gasification in the coming years. In June 2020, Prime Minister Narendra Modi announced plans for Rs. 20,000 crore (\$2.7bn) of investment in coal gasification, to deliver approximately 100 Mt of capacity (Economic Times, 2020). Major suppliers, such as AirProducts, have also stated their intent to expand the role of coal gasification in India, planning investments of \$5–10bn in the next 5–10 years (Hindu Business Line, 2020).

Coal gasification is highly polluting, producing twice the amount of CO₂ emissions of natural gas-based hydrogen production. As such, for coal gasification to be able to play a role in reducing emissions from India's energy system, CCUS technology will be required.

3.1.5.2 Techno-economic Analysis

We examined both above-ground and under-ground coal gasification units. We considered two scenarios, high and low, for both types of units based on coal prices. The assumptions given in Table 5 on Capex, Opex, efficiency, and capture rate for coal gasification technologies and Capex, Opex for CCS technologies, and energy penalty to the gasification process for CCS technologies are used. We also assume the following prices for coal (see Table 5).

Table 5: Coal gasification assumptions

Tech / Input	Metric	Unit	2020	2030	2050
Coal gasification	Capex	Rs/kW	185,000	185,000	185,000
	Opex	% Capex	10	10	10
	Efficiency	%	55	55	55
Under-ground coal gasification	Capex	Rs/kW	118,400	118,400	118,400
	Opex	% Capex	10	10	10
	Efficiency	%	55	55	55
CCS	Capex	increase	+5%	+5%	+5%
	Opex	increase	+130%	+130%	+130%
	Fuel	increase	+5%	+5%	+5%
Coal	Price	Rs/tonne	3,700–6,660	3,700–6,660	3,700–6,660

Sources: (BEIS, 2020; BEIS, 2018; IEA, 2019)

Figure 9 shows the levelized cost of hydrogen in Rs/kg from coal gasification above and underground in the high and low scenarios. We find that the costs of hydrogen production from coal gasification without CCS (grey hydrogen) would approximately be Rs 150–300/kg depending on the cost of coal and the production route. Some share of higher quality coal would have to be imported, given the high ash content of India’s domestic coal, which is unsuitable for most commercially available gasification units. With CCS, costs would increase up to Rs 400/kg for above ground gasification and around Rs 240/kg for the underground route.

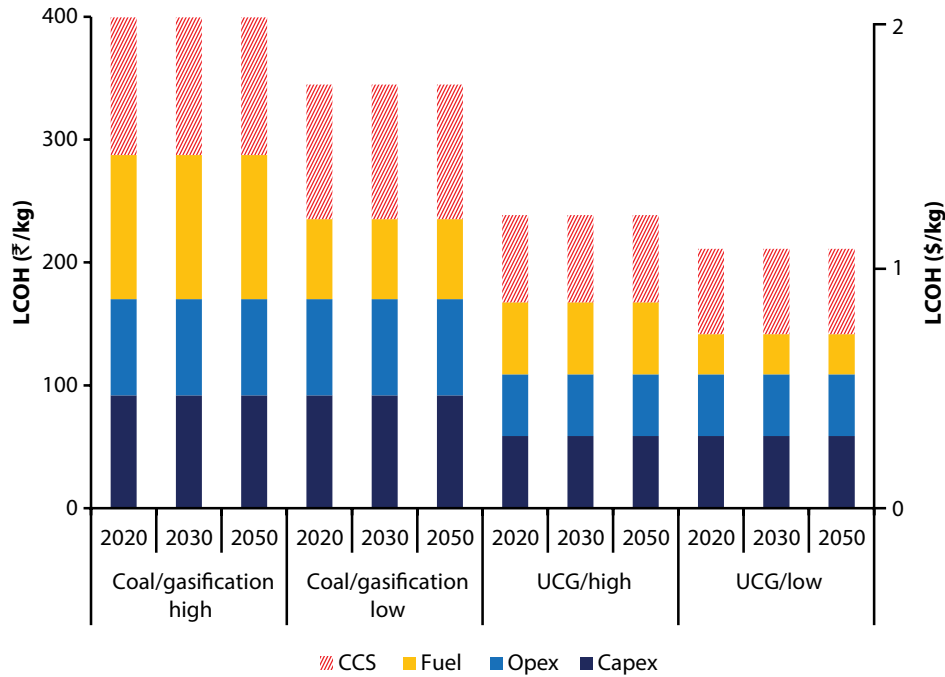


Figure 9: Levelized costs of hydrogen from coal gasification, 2020, 2030, 2050

Source: TERI analysis based on (BEIS, 2018; IEA, 2019; BEIS, 2020)

Note: UCG = underground coal gasification; Fuel = coal

3.1.6 Other Considerations

3.1.6.1 Quality of Indian Coal

Globally available coal gasification technologies are designed for coal with relatively low ash content and may not be suitable for Indian coal, which has a higher ash content. Existing gasification projects rely on some share of imported coal with lower ash content to improve efficiency and reduce operating costs. India may use domestic resources if gasification technology becomes available that enables use of high ash coal. Otherwise, there would be a continued need to import higher-quality coal. As a result, this would negate the potential energy security and trade balance benefits of coal gasification.

3.1.7 Other Potential Technologies

Apart from the three main commercially available routes discussed earlier, there are a number of other emerging hydrogen production technologies that could also play a role in supplying low carbon hydrogen. These include biomass gasification, methane pyrolysis, photolysis, and microbial biomass conversion.

3.1.7.1 Biomass Routes

Hydrogen production using biomass is possible through biochemical and thermochemical processes. Biochemical routes use either microorganisms on organic material to produce biogas (anaerobic digestion) or a combination of acids, alcohols, and gases (fermentation).

The thermochemical gasification process is similar to coal gasification, as it converts biomass to a mix of carbon monoxide, CO₂, hydrogen, and methane through a high temperature heat process. Although anaerobic digestion is the most technically mature process, it can only process sewage sludge, agricultural, food processing and household waste, and some energy crops.

The main challenge for deploying biomass technologies at scale will be the limited availability of sustainably sourced biomass. The optimal biomass sources on a life cycle emissions basis include agricultural residues and organic municipal waste, both of which are relatively limited. Nonetheless, maximizing reuse of this waste in bio-hydrogen production routes could be a cost-effective way of meeting a portion of hydrogen demand.

The Government of India is exploring hydrogen production using anaerobic digestion. The programme aims to produce biogas from agricultural residues. The cost of hydrogen from this production process is expected to be approximately Rs 200/kg (below \$3/kg). The government has a target of constructing 5,000 biogas plants by 2023, although most of this is currently targeted at the transport CNG market, not at hydrogen production (Bloomberg Quint, 2018).

3.1.7.2 Methane Pyrolysis

Methane pyrolysis, also known as ‘turquoise hydrogen’, uses a hydrocarbon feedstock such as natural gas to produce hydrogen, separating the carbon by converting it into solid carbon. As a result, the process greatly reduces CO₂ emissions and enables easy storage or use of solid carbon instead of CO₂. Whilst relatively early in its development, the costs of producing turquoise hydrogen have the potential to be similar to conventional SMR (Ammonia Energy Association, 2020).

BASF SE in collaboration with Linde Gas, Thyssenkrupp, and several German research institutes is currently exploring this route of production. The consortium is exploring this process as a way to support low carbon hydrogen production for them and their customers. Shell and TNO are also exploring this technology (Industry & Energy, 2020) .

3.1.7.3 Photolysis

Photolysis is the process of using light directly to split water into hydrogen and oxygen. There are different ways of photolysis, with photobiological and photoelectrochemical water splitting being two key technologies. Both processes use sunlight as the energy source but differ in the mechanism of hydrogen production – photobiological splitting uses microorganisms such as green algae to split water, and photo-electrochemical splitting uses catalysts similar to those employed in electrolyzers for water splitting.

Hydrogen production from photolysis is still in the early stages of research but could have significant long-term potential for sustainable hydrogen production with a negligible environmental impact. Improvements in efficiency, durability, and costs are all needed for photolysis to start competing with other leading routes, such as electrolysis (DOE, 2020).

Research into this technology in India is currently being taken forward by IIT Delhi, IISc Bangalore, IIT Madras, IIT Kanpur and IIT (Banaras Hindu University) among others (Department for Science and Technology, 2020).

Box 4: The potential for carbon capture, usage, and storage (CCUS) in India

Without a comprehensive study assessing CO₂ storage potential for different sites, it is challenging to conclude on the potential for CCUS in India. There is significant uncertainty in the overall potential, as well as the costs for developing CO₂ storage sites.

Apart from a few small-scale demonstration projects, India currently has no major CCUS projects (Datta & Krishnamoorti, 2019). The largest CCU operations are for enhanced oil recovery (EOR) and recycling CO₂ in fertilizer production for urea. The Department for Science and Technology (DST) oversees innovation activity for CCUS, with other ministries playing a vital supporting role, including the Ministry of Mines.

In a comprehensive study from 2009, it was estimated that there was potential storage of 345 MtCO₂ in major coalfields and 2–7 GtCO₂ in oil and gas reservoirs. Whilst seemingly large in aggregate, these storage sites tend to be relatively small and disparate, significantly adding to the cost of their development (Holloway, *et al.*, 2009). It is also the case that many of the coal seams would still be in use for many years, preventing their use as CO₂ storage sites. Moreover, there are some concerns that some of the coal seams in India are too shallow to provide a long-term CO₂ storage option (Figure 10).

For example, a large steel plant, such as Tata Steel's 8 Mt per annum facility at Kalinganagar, would emit approximately 20 MtCO₂ each year. Over the course of its lifetime of around 40 years, the plant will emit a total 800 MtCO₂, which is far larger than the capacity of individual fields. This would require the development of multiple CO₂ storage sites, thereby greatly increasing the costs.

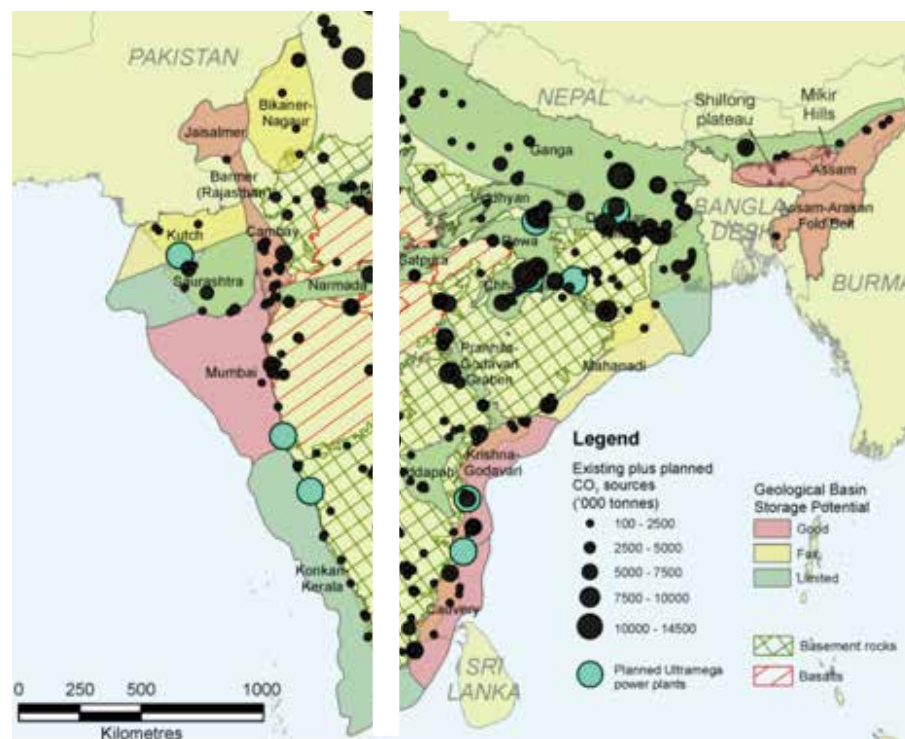


Figure 10: Map of CO₂ sources and potential storage sites (West India left, East India, right)

Source: (Holloway, *et al.*, 2009)

The alternative option is to use the captured CO₂ in other industries, such as chemicals and petrochemicals, food and drink processing, or agriculture. This has the added benefit of generating additional revenue streams if the CO₂ can be sold. However, there are two potential issues with such an approach.

First, CO₂ usage is dependent on there being a sufficiently large demand for CO₂, bearing in mind that other large industrial sectors, such as cement, have no alternative than using CCUS to remove process emissions. Today, about 220 MtCO₂ is used globally for various industrial processes (Naims, 2016). Assuming 3% of this demand is located in India in line with its share of global economic activity, this would result in approximately 10 MtCO₂ demand in India today. Total emissions from India's energy and industry system today are around 2,654 MtCO₂ per annum (Global Carbon Project, 2019), meaning that CCU could only cater for around 0.4% of emissions. Of course, demands for carbon may increase over time with new uses across a range of sectors (such as enhance oil recovery [EOR], methanol, polymers, etc.) but it is likely that supply will continue to significantly outstrip demand.

The second issue is that in most cases CCU does not result in a significant reduction in CO₂ emissions. This is because for most examples of CO₂ use, for instance, carbonating drinks or adding to ammonia to make urea, most of the carbon is still eventually released into the atmosphere – using it again simply recycles the CO₂ instead of preventing it from being emitted. Whilst this may still be useful as a transition towards deeper decarbonization, it is important to recognize the limitations in terms of emissions reduction.

3.1.8 Comparison

3.1.8.1 Costs

Today, the costs of producing low carbon hydrogen, either green or blue, would be significantly more expensive than producing hydrogen derived from fossil fuels. This is true around the world, where costs of natural gas and coal are relatively low, versus the costs of electricity. Moreover, the costs of electrolyser technologies, whilst expected to fall rapidly in the coming years, are currently quite high in most regions. Nonetheless, a few important conclusions from this analysis are important to draw out.

The cost differential between natural gas and electricity in India makes it particularly well-suited to green hydrogen production in the near term

Whilst domestic natural gas prices are relatively low, the supply of this gas is limited, as discussed earlier. As such, any major expansion in hydrogen production using natural gas would need to use imported natural gas, which would be at a significantly higher cost than domestic gas. Imported natural gas prices in India can be 3–4 times the prices seen in other parts of the world, such as the United States.

India has some of the lowest renewable generation costs, with both solar PV and onshore wind among the cheapest in the world (NREL, 2020). If India were to scale up green hydrogen production, solar PV would be the main source of renewable electricity. In other parts of the world, costs of electricity generation from solar PV are much higher – both in absolute terms as well as relative to natural gas. Figure 11 shows that most developed countries have higher solar PV costs relative to their natural gas prices, with only China and India exhibiting relatively lower solar costs than natural gas. As a result of this price differential, it would make more sense for India to expand green hydrogen production versus grey or blue hydrogen.

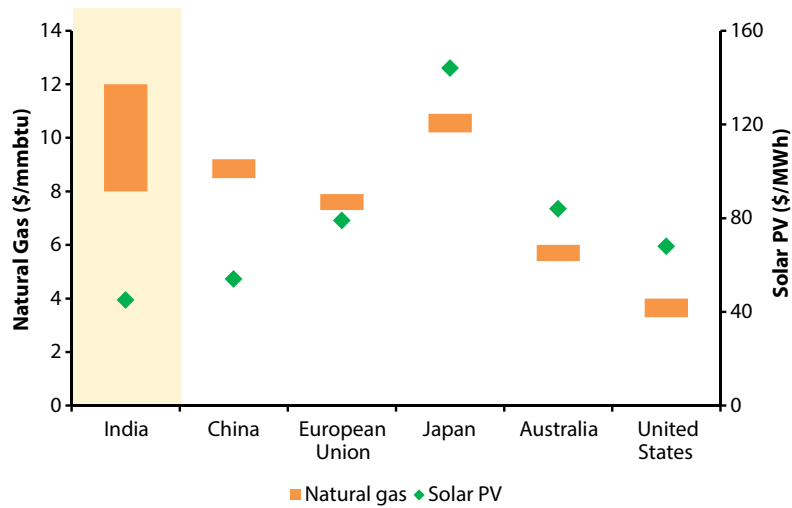


Figure 11: Natural gas vs solar prices in different regions

Source: TERI analysis based on (IEA, 2019; NREL, 2020)

Green hydrogen will be competitive with grey hydrogen by 2030, if not before

Looking out to 2030, when demand for hydrogen starts to ramp up, costs of green hydrogen production will reach equivalence with costs of grey hydrogen (from natural gas). There are significant uncertainties in the key inputs, including capital costs, operational costs, and costs of fuel or electricity. Figure 12 illustrates these uncertainties over the 2030 time frame, showing that with more ambitious assumptions around electrolyser cost reductions, we could see green hydrogen undercutting grey hydrogen well before 2030. The main driver of uncertainty for grey hydrogen is the price of natural gas.

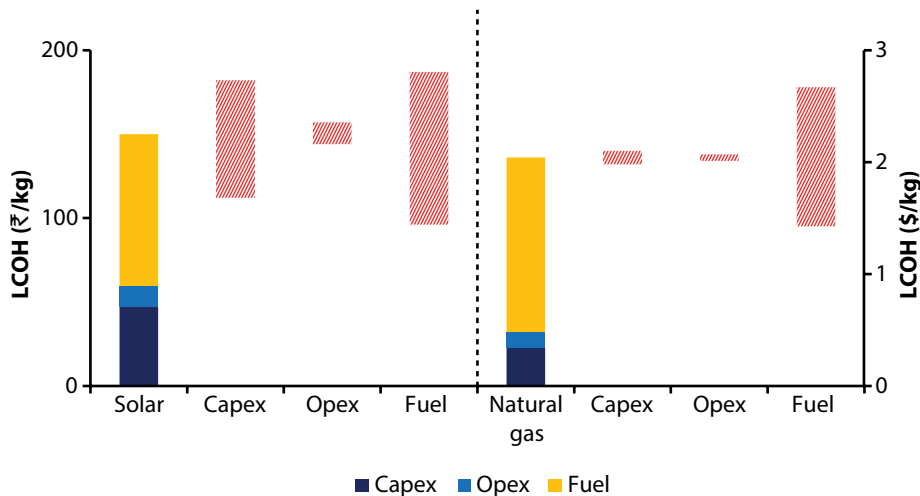


Figure 12: Standalone vs natural gas costs of hydrogen production, 2030

Source: TERI analysis based on (IEA, 2019; BEIS, 2018; BNEF, 2020).

Note: Left-hand fuel = electricity, right-hand fuel = natural gas. Red bars reflect sensitivity range for various elements.

Green hydrogen from standalone renewable systems will be more cost-effective than grid-connected electrolysis

Given green hydrogen is likely to be cost-competitive with the grey route by around 2030, if not before, it is worth making clear that both from a cost and an emissions standpoint, this relies on the deployment of standalone renewable systems (Figure 13). By this we mean renewable generation assets that are not connected to the wider grid and are therefore exempt from grid charges, which are particularly significant for industrial users in India. Whilst grid connected electrolyzers can benefit from higher utilization rates, this is outweighed by higher electricity costs, as indicated earlier.

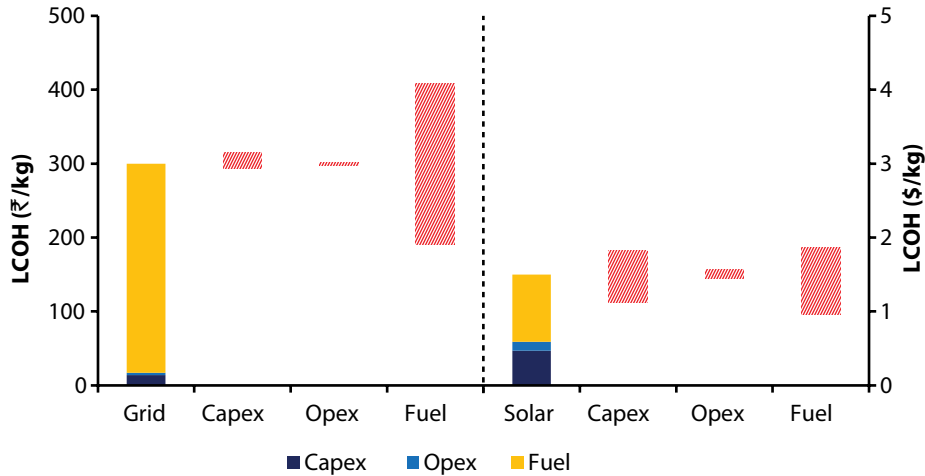


Figure 13: Grid vs standalone electrolysis costs of production, 2030

Source: TERI analysis based on (IEA, 2019; BEIS, 2018; BNEF, 2020)

Note: Fuel = electricity. Red bars reflect sensitivity range for various elements.

In the sensitivity analysis, we can see that even if we assume grid-connected electrolyzers are able to access much cheaper electricity prices (around half of today’s average), the costs of hydrogen generation would still exceed standalone renewable systems. This reinforces the point that hydrogen expansion in India should focus on standalone systems, to guarantee low cost, low emission hydrogen production.

3.1.8.2 Emissions

Given the important role that hydrogen can play in reducing emissions from India’s energy system, it is important to understand the relative benefits of each production route in terms of their emissions intensity. We have estimated the emissions intensity using efficiencies for various technologies (stated in Tables 3, 4, and 5), multiplied by the emission factors of the different fuels.

As expected, unabated fossil fuels result in significant emissions from hydrogen production, with coal-based production (brown) exceeding 600 gCO₂/kWh. Natural gas-based production is significantly less, driven by both lower emissions intensity of natural gas as well as higher efficiencies of methane reformation versus coal gasification (Figure 14). We estimate that emissions from unabated gas-based hydrogen production is less than half of coal-based production – an important consideration in the context of India’s plans to expand coal gasification elsewhere in the economy.

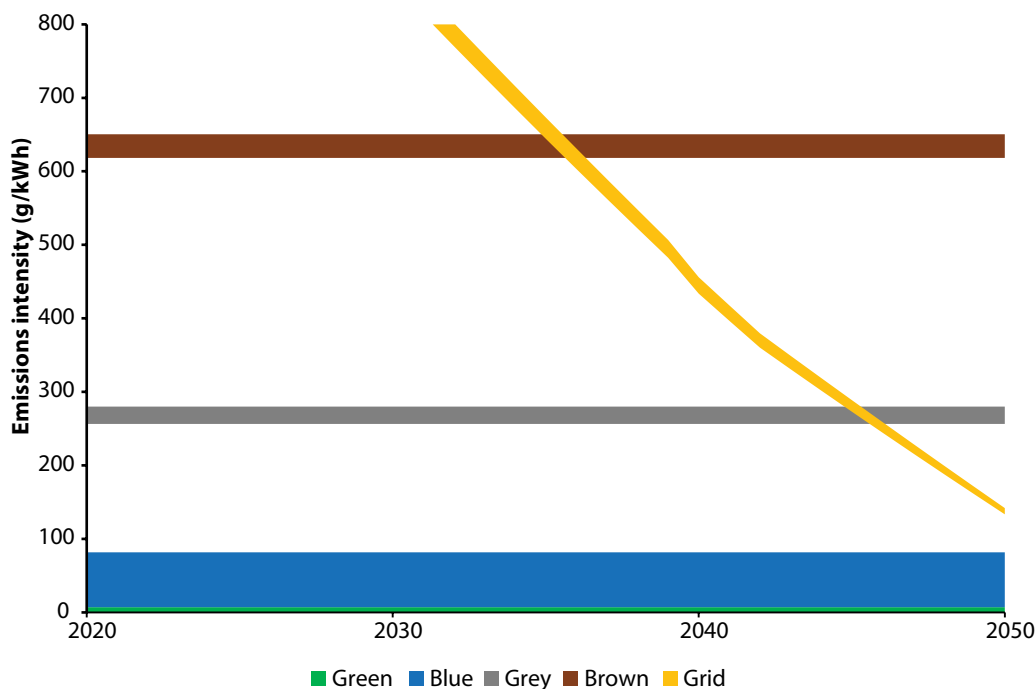


Figure 14: Emissions intensity of hydrogen production, 2020–2050

Source: TERI analysis based on (BEIS, 2018; IEA, 2019; BEIS, 2020; GHG Platform India, 2019)

Another key finding from this emissions intensity analysis is the significant emissions from hydrogen production using grid electricity. The Indian electricity grid is currently at around 700gCO₂/kWh, although this is expected to decrease rapidly over the time period, in line with ambitious renewable energy targets (Spencer, Rodrigues, Pachouri, Thakre, & Renjith, 2020). Nonetheless, with today’s emissions intensity of grid electricity, taking into account the efficiency penalty of electrolysis, hydrogen produced from the grid would have an emissions intensity over 1,000gCO₂/kWh, higher even than coal-based hydrogen production. This reinforces our recommendation that electrolytic hydrogen should be constructed using dedicated renewables versus grid electricity, both for reasons of costs and emissions.

The range in emissions intensity from blue hydrogen production is driven by the range of potential capture rates from CCS infrastructure, with 60% on the low end and 97% on the higher end (IEA, 2019; BEIS, 2020). As countries seek to reduce emissions further towards the mid-century, higher capture rates will become increasingly important to remove residual emissions from the energy system.

However, for natural gas-based production, it is also important to consider the upstream emissions from the natural gas supply chain, including pre-production, extraction, processing transmission, storage, and distribution (Figure 15). Estimates on upstream emissions vary widely based on the location but a median estimate based on the available literature suggests that an additional 48 gCO₂/kWh would be emitted, adding approximately 25% to natural gas emissions. The upper end of estimates sees an additional 160 gCO₂/kWh being emitted upstream, equating to an additional 80% to the emissions intensity of natural gas. It is therefore important that any expansion of natural gas-based hydrogen production takes into account potential upstream emissions, and steps are taken to minimize these as far as possible. Through implementing best available technologies and minimizing methane leaks and vents, upstream emissions can be significantly reduced across the supply chain.

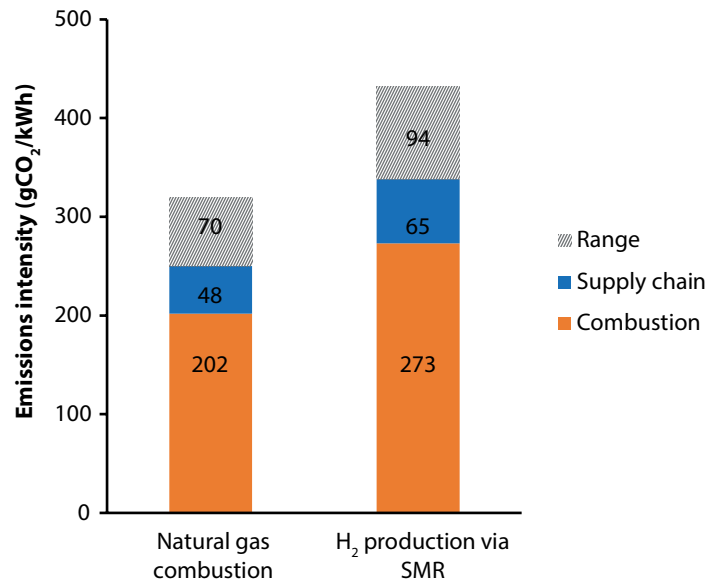


Figure 15: Upstream emissions from the natural gas supply chain

Source: TERI analysis based on (Balcombe, Anderson, Speirs, Brandon, & Hawkes, 2015; BEIS, 2020; BEIS, 2018)

3.2 Transportation of Hydrogen

There are two models for hydrogen production and transportation in India; an on-site, distributed production model, where users are co-located with production assets, and a production hub and grid model, similar to the current natural gas infrastructure set-up. To understand the appropriate model for different end-use cases, it will be important to evaluate the relative costs of transporting different quantities of hydrogen over different distances. In this section, we cover the three main ways of transporting hydrogen: pipelines, trucks, and shipping.

3.2.1 Pipelines

Globally, today, most hydrogen is produced and consumed on-site (85%), with the remainder being transported by trucks or pipelines (BNEF, 2019). This is largely because it is safer and cheaper to transport natural gas (main fuel for hydrogen production) than hydrogen. In terms of safety, hydrogen is highly flammable and more prone to leakage given its molecular size. This means pipelines need to be designed with higher specifications to minimize leakage. Whilst this is clearly possible, as illustrated by the hundreds of kilometres of hydrogen pipelines that exist today, it makes more sense to transport natural gas, which has a higher energy density by volume, meaning smaller or fewer pipelines are required.

Transporting pure hydrogen as a liquid requires the hydrogen to be cooled to -253°C . The cooling, refrigeration, and regasification are all incredibly energy-intensive and can result in energy losses of around 25–35% (BNEF, 2019).

Alternatively, hydrogen can be transported in the form of ammonia, methanol and Liquid Organic Hydrogen Carriers (LOHCs). Although easier to transport, if not used directly (such as ammonia and methanol), these fuels would need to be processed further to release hydrogen, before final consumption. This involves extra energy and costs, which must be balanced by lower transport costs (IEA, 2019).

Whilst pipelines are the preferred transportation method, high initial capital costs for their construction can be a major barrier. Moreover, there are some outstanding technical concerns related to retrofitting existing pipelines

for hydrogen transport, including the potential for hydrogen to embrittle the steel, whereby hydrogen atoms are absorbed by steel, potentially leading to cracks in the pipe. This problem is well understood, and several solutions exist, including lining steel pipes or using plastic pipes instead (e.g. polyethylene) (Northern Gas Networks, 2016).

3.2.2 Trucks

At lower volumes, or where pipelines are not feasible, transporting hydrogen via trucks is also an option. This would be done using compressed gas tankers at high pressure or liquid hydrogen, carried in insulated, cryogenic tankers. Given the low quantities that can be transported using trucks, this distribution mode would be limited to smaller end-users (such as hydrogen refuelling stations) or industrial demonstration projects. As soon as hydrogen demand exceeds the tens of tonnes per day (tpd), a pipeline becomes a more cost-effective option. It is expected that compressed gas tube trailers and liquid hydrogen trucks will remain the main distribution modes over the next decade, as hydrogen use is still scaling up (IEA, 2019).

Pressurized tube trailers operate at pressures between 200 and 500 bar to carry small volumes of compressed hydrogen over shorter distances; for longer distances and for larger quantities, transporting hydrogen in liquid form is preferable. The main drawback with carrying liquid hydrogen is ‘boil-off’, whereby some hydrogen is lost if the low temperatures are not maintained (Department for Science and Technology, 2020).

Table 6: Costs of hydrogen transportation

Technology	Year	Unit	Cost	Description
Transmission Pipeline	2020	Rs/kgH ₂	2.2	50KM distance; 1000tpd
	2050	Rs/kgH ₂	1.5	50KM distance; 1000tpd
Distribution Pipeline	2020	Rs/kgH ₂	6.7	50KM distance; 100tpd
	2050	Rs/kgH ₂	5.2	50KM distance; 100tpd
Truck	2020	Rs/kgH ₂	11.8	50KM distance; 700 kg capacity
	2020	Rs/kgH ₂	40.0	50KM distance; 200 kg capacity

1 Mtpa Steel Plant approx. 150tpd

↑

Refueling station up to 1tpd

Source: (BNEF, 2019)

3.2.3 Shipping

Shipping is likely to remain a high-cost option even in 2050 due to costs of liquefaction, refrigeration, and regasification. For certain routes, the use of ammonia may be feasible, but it will depend on significant disparities in the costs of hydrogen production in different regions. As the costs of renewable electricity generation continue to fall in all regions around the world, the absolute differences between green hydrogen production costs will reduce, making the case for long-distance shipping weaker. We expect India will have sufficient domestic renewable resources to be able to supply its own market, thereby minimizing the need for ammonia imports.

3.3 Storage of Hydrogen

To meet constant demands from industrial users, paired with hydrogen produced from variable renewables, hydrogen storage will be required. Hydrogen can be stored physically as a gas or liquid. The storage of hydrogen as a gas in vehicles requires high pressure (around 350–700 bar) due to space constraints but can be stored at lower pressures for stationary applications (around 100 bar). Storage as a liquid requires cryogenic temperatures

(−253°C) (BNEF, 2019). The appropriate storage medium depends on the volume to be stored, duration of storage, required speed of discharge and the geographic availability of different options (IEA, 2019). We briefly discuss two storage options: geological storage and steel tanks (Table 7).

3.3.1 Geological Storage

The chemical sector in the UK and the US has been using salt caverns for hydrogen storage since the 1970s and 1980s. Salt caverns are one of the most cost-effective ways for storing hydrogen at around Rs 3.7/kg, have an efficiency of storage of around 98%, and have low risk of contaminating the hydrogen that is stored. High pressures enable high discharge rates and make them attractive for industrial and power sector applications. Although salt caverns are the cheapest form of hydrogen storage, it is unlikely that India has sufficient suitable salt deposits for this to be an option. The next most cost-effective options are either rock cavern storage or reusing depleted hydrocarbon reservoirs. Depleted oil and gas reservoirs tend to be larger than salt caverns but they are more permeable and contain contaminants that would have to be removed before the hydrogen can be used in fuel cells (IEA, 2019). Further work needs to be done to understand their potential in geographically relevant locations for India.

3.3.2 Steel Tanks

The most expensive but commonly used hydrogen storage method is high-pressure steel tanks. These above-ground storage tanks have a few limitations on siting compared to other geological options. Tanks storing compressed or liquefied hydrogen have high discharge rates and efficiencies of around 99% making them appropriate for smaller-scale applications where a local stock of fuel or feedstock needs to be readily available (IEA, 2019).

Compressed hydrogen (at 700 bar pressure) has only 15% of the energy density of gasoline, meaning storing the equivalent amount of energy at a vehicle refuelling station would require significantly more space. It is also the case that steel tanks tend to be far smaller than geological formations, requiring many more facilities for a country such as India, where geological storage is uncertain.

Ammonia has greater energy density, which reduces the need for large storage tanks but this advantage would have to be weighed against the energy losses and equipment for conversion and reconversion when end uses require pure hydrogen. Research into finding the ways to reduce the size of tanks, and looking at the scope of underground tanks that can tolerate 800 bar pressure is being undertaken (IEA, 2019).

Indian Oil Corporation Limited (IOCL) is also working on the development of a Type-3 High Pressure Hydrogen Cylinder in collaboration with IIT Kharagpur. The cylinder increases the energy storage density over existing cylinders. They are also working on developing material-based hydrogen storage including metal-organic frameworks (MOFs). Their research is focused on producing high energy density MOFs, which can be scaled up cost-effectively.

Table 7: Costs of hydrogen storage

Technology	Year	Unit	Cost	Description
Salt cavern storage	2020	Rs/kgH ₂	3.7	Salt cavern storage (20% vol.)
	2050	Rs/kgH ₂	1.5	Salt cavern storage (20% vol.)
Rock cavern storage	2020	Rs/kgH ₂	10.4	Rock cavern storage (20% vol.)
	2050	Rs/kgH ₂	3.7	Rock cavern storage (20% vol.)
Steel tank	2020	Rs/kgH ₂	48.1	700kg capacity
	2050	Rs/kgH ₂	40.0	1,100kg capacity

Source: Average levelized costs of storage based on (BNEF, 2019)

Note: 20% vol. refers to the share of geological formations which is usable for hydrogen storage and extraction. The remaining 80% vol. remains constant to maintain the structural integrity of the store.

For higher-pressure tanks to be used in India (up to 700 bar), the regulations governing gas cylinders must be updated. In a positive move, in September 2020, the Ministry for Road Transport and Highways notified the Standards for Safety Evaluation for vehicles propelled by hydrogen fuel cells, to allow testing of vehicles using higher pressure tanks, in line with international standards (MoRTH, 2020).

4

TRANSPORT



Key messages

- The extremely rapid cost reductions in battery technologies, alongside performance improvements, make BEVs competitive in most segments.
- From the medium-term, BEVs will dominate most of the smaller, shorter-range passenger vehicles, including two-, three-, and four-wheelers, as well as city buses and last-mile freight.
- FCEVs could remain competitive in longer-distance, heavier-weight vehicle segments.

4.1 Introduction

The transport sector accounts for 17% of India's total energy consumption. Within transport, oil products are the dominant fuel with transport accounting for 47% of India's oil product consumption. India is dependent on imports for 85% of its crude oil supplies, which represent a major drag on the balance of payments (IEA, 2020). Transport emissions are also an important source of local air pollution emissions, and thus contribute significantly to India's air pollution problem. At the same time, access to high-quality and affordable transport services is inhibited by the lack of supply of sufficient and convenient public transport, and the high cost of private modes of transport.

In this section, we analyse the potential role of hydrogen in a transport transition towards a more sustainable and economic system. We focus on road transport as the main sector where hydrogen is likely to be deployed. Other transportation sectors including rail transport, shipping and aviation are not considered in detail in this report. We start with a discussion on the relative efficiencies of internal combustion engine (ICE), electric and hydrogen fuel cell drivetrains; then present long-term analysis for the Total Cost of Ownership (TCO) of different drivetrains in different vehicle segments; and conclude with a presentation of long-term transport scenarios.

4.2 Understanding Conversion Efficiency of ICE, Electric, and Hydrogen Drivetrains

The vehicle drivetrain converts the chemical or electrical energy of the fuel into mechanical or motive energy. This conversion efficiency is an important determinant of the overall cost and environmental impact of the drivetrain type. However, it is also important to consider the conversion efficiency of the processes of production, storage, and distribution of the fuel. This is particularly the case for hydrogen fuel cell electric vehicles (FCEVs), because conversion losses in the upstream processes of fuel production are significant.

Figure 16 shows the full value chain conversion efficiency of an FCEV versus a pure electric vehicle. Both processes start with the input of electricity, envisaged in Figure 17 as an input of 100 units. This assumes that the source of hydrogen for the FCEV is electrolytic hydrogen, which was identified in Section 3 as the most likely source of low carbon hydrogen to be competitive in the Indian context. The process of electrolysis has a conversion efficiency in the order of 70% (30 units of energy input are lost), while transmission, distribution, and storage (TDS) incur a further loss of 26%. In the case of direct electrification in a battery electric vehicle (BEV), the electrolysis stage is skipped, and about 5% losses are incurred in the TDS phase. Subsequently, small losses are incurred in the BEV as AC current is converted to DC current to charge the battery and in the battery charging process itself. Losses in these phases in the case of the FCEV are zero. In the case of FCEV, the next phase involves the conversion of hydrogen into electricity, which drives the electric motor powering the vehicle. This phase incurs a further 50%

conversion loss. In the case of BEV this phase is skipped. Finally, both drivetrains incur minor losses in the conversion of DC current back to AC current, and in the conversion of electrical energy to mechanical energy in the electric motor (respectively losses in the order of 5% and 10%).

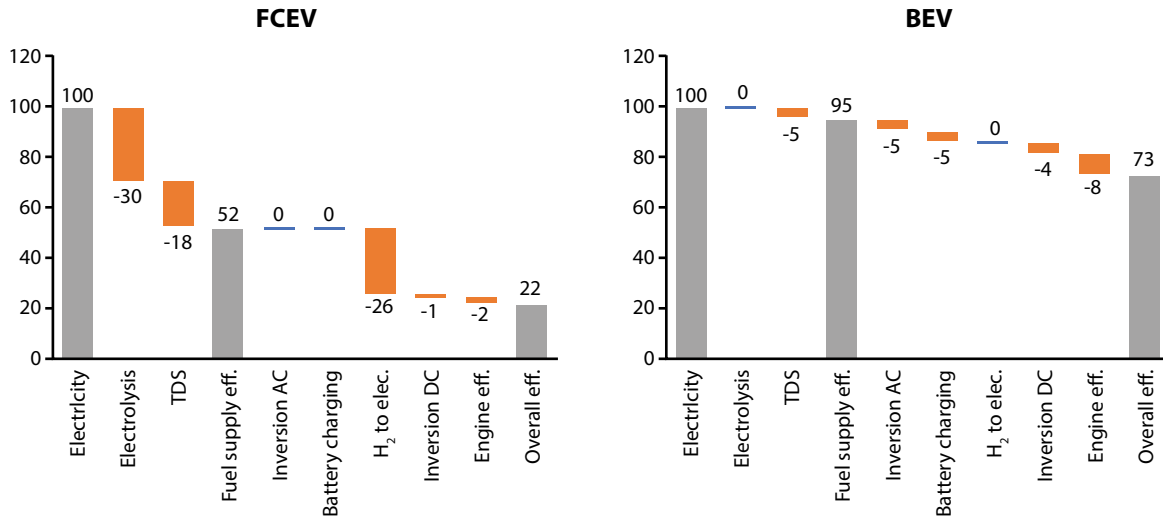


Figure 16: Value chain conversion efficiency of FCEV (left) versus BEV (right)

Source: TERI analysis

Note: TDS = Transmission, distribution, and storage

The end result of this process is that in the case of FCEV, only about 22% of the input electricity is converted into mechanical energy powering the car, with the rest being sundry conversion losses across a value chain requiring multiple energy conversions. In the case of BEV, 73% of the input electricity is converted into mechanical energy, as the value chain skips several energy conversions where losses accumulate in the case of FCEV. For comparison, the conversion efficiency of an internal combustion engine vehicle is in the order of 33%. Adding upstream conversion losses in the fuel production and refinery process would bring the full value chain conversion efficiency of ICE vehicles into a similar range as the value chain conversion efficiency of FCEVs.

These accumulated conversion losses matter for several reasons. First, they negatively impact the economic competitiveness of FCEVs, as more input electricity must be purchased to drive a given level of mechanical energy output. Second, in the context where the growth of zero-carbon electricity supply may be constrained (see Section 6), its use must be made as efficient as possible. This means prioritizing direct electrification wherever technically possible and economically attractive. Third, if the input electricity is not 100% zero carbon, the cumulative conversion losses of FCEV mean that per KM CO₂ emissions will be proportionally higher when emissions upstream of the tailpipe are considered (indeed, the same holds for other emissions, such as local air pollutants).

4.3 Total Cost of Ownership Assessment

4.3.1 Introduction

We now turn to a long-term assessment of the relative economics of different drivetrain types and different fuels in various segments. To do so, we develop a Total Cost of Ownership (TCO) model. The concept of TCO is similar to that of the Levelized Cost of Electricity (LCOE), which is commonly used in power sector analysis. It represents a single metric of lifetime per kilometre costs of acquisition and operation of the transport vehicle. The basic formula is lifetime discounted fixed and variable costs, divided by lifetime discounted kilometres travelled. The following points discuss several complexities within this framework:

- Discount rate:** The discount rate is used to convert future costs into a present value. It broadly reflects the cost of capital of the purchaser. Different agents may have different discount rates, reflecting their different costs of capital, rates of time preference, and aversion to risk or uncertainty. A higher discount rate makes upfront costs more important in the TCO calculation, while diminishing the importance of future costs. Because the cost structure of BEVs is weighted towards upfront capital costs, while that of ICE is weighted towards lifetime fuel costs, higher discount rates tend to penalize BEVs. In this study, we use a single discount rate of 15% across all vehicle segments, drivetrain types and fuels. This is probably higher than what a public sector discount rate should be (Government of India can borrow at 5–6%), but possibly lower than what a household discount rate is.
- External costs:** How the system boundary of the TCO calculation is drawn is important. For example, the inclusion of infrastructure costs is particularly important in the case of BEVs and FCEVs, where substantial new infrastructure would be required. However, determining the cost of this infrastructure requirement is not an easy task, because what matters is how it is distributed across users and society at large. On a per unit basis, initial infrastructure costs may be substantial as they are levelized across a lower number of initial users. As the number of users increases, per unit costs fall. Finally, infrastructure costs are often not fully incurred by users, but are socialized to a degree across society. In this study, we exclude infrastructure costs from the TCO analysis, although the sensitivities we present on fuel prices can be thought of as covering cases where infrastructure costs are internalized within fuel prices.
- Non-Monetary Costs:** Technological transitions are often inhibited by factors to which it is difficult to attach a monetary value. Examples include range anxiety, uncertainty on technological performance, the persistence of supportive policy, or convenience costs related to charging times, etc. In this study, we do not directly include non-monetary costs. However, in Section 4.3.2, we conduct a multi-criteria assessment which includes these kinds of non-monetary costs. Furthermore, the long-term scenarios that we develop are based on this multi-criteria assessment, not solely upon the TCO assessment.
- Policy:** The development of policy will be crucial to the transition towards alternative drivetrains. This is true even if the TCO of an emerging technology is favourable, for example in the case of BEVs in certain segments today. This is because of the importance of factors that are not included in the TCO calculations, including infrastructure development. Other policy developments, including fuel taxation and electricity pricing, are uncertain. We do not assume fundamental shifts in energy taxation; our transport scenarios developed in Section 4.5 are conservative regarding the development of the necessary enabling infrastructure.

Table 8 presents selected key assumptions of the TCO model. It should be noted that we present multiple sensitivities in the following paragraphs, with the objective being to show the key drivers of tipping points for different drivetrains in different segments.

Table 8: Key selected assumptions for the TCO model

Year	Discount Rate (%)	ICE Fuel Price			Electricity Price (Rs/kWh)	Hydrogen Price (Rs/kg)	Battery Cost (Rs/kWh)	Fuel Cell Cost (Rs/kW)
		Petrol (Rs / Litre)	Diesel (Rs /Litre)	CNG (Rs /Kg)				
2020	15%	75	70	55	7	560	14,000	7,000
2030	15%	83	77	67	7	280	5,452	5,162
2050	15%	101	94	100	7	154	3,791	3,446

Source: TERI analysis based on prices from (IEA, 2020; ICCT, 2020)

Note: Assumed real escalation rate of 1% for petrol and diesel, and 2% for CNG to Indian context; base year 2019.

4.3.1.1 Light Duty Passenger Transport: Two- and Three- wheelers, and Passenger Cars

Figures 17 and 18 show the results of the TCO model for two-wheeler and four-wheeler segments, respectively. For two-wheelers, neither hydrogen nor CNG vehicles were modelled. The results for two-wheelers are relatively clear: electric two-wheelers are competitive with ICE two-wheelers already as of 2020. As noted earlier, this excludes the cost of charging infrastructure, which is likely to be small given the low size of required BEV batteries, in both power and energy terms. BEV two-wheelers are already a lower carbon option than ICE two-wheelers, even at current CO₂ intensities of the Indian grid. This is because the far superior conversion efficiency of the

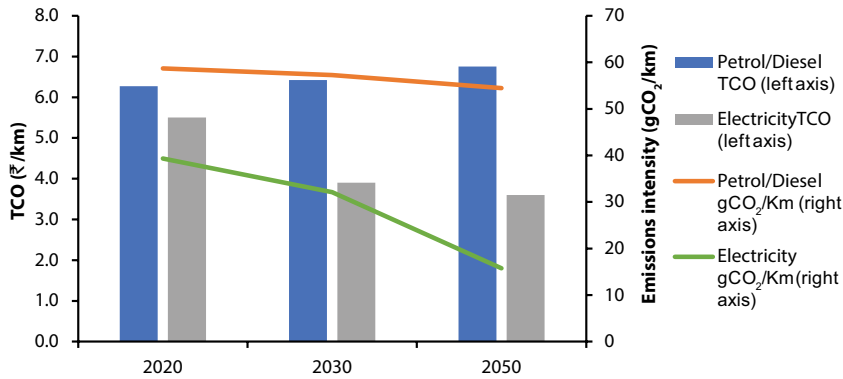


Figure 17: Two-wheeler TCO and CO₂ intensity, 2030 to 2050
Source: TERI analysis

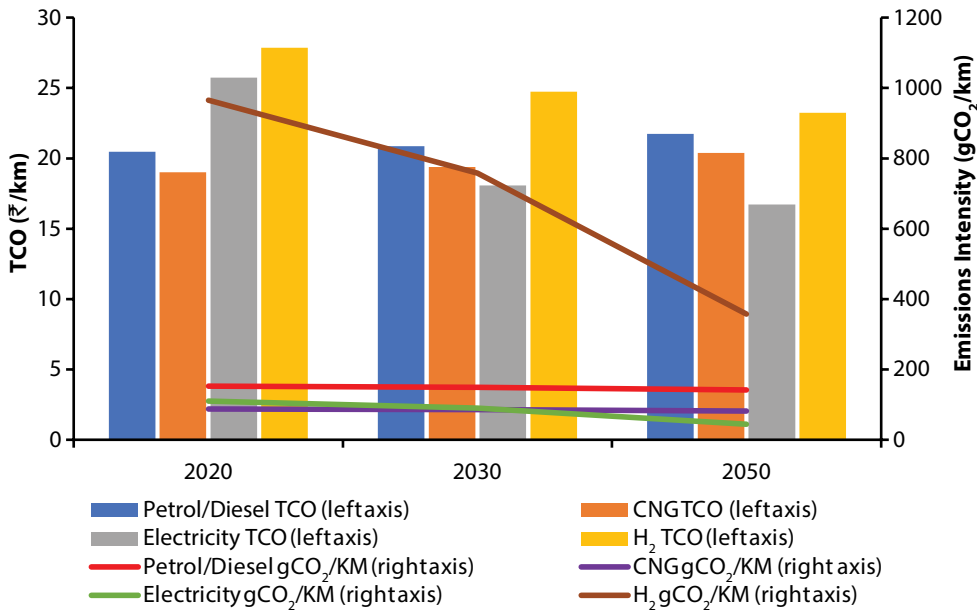


Figure 18: Four-wheeler TCO and emissions intensity, 2020, 2030, and 2050
Source: TERI analysis

BEV drivetrain is more than enough to compensate for the higher carbon intensity of today's electricity grid. The grid emissions factor today is around 700 gCO₂/kWh, compared to 266 gCO₂/kWh for petrol. With the conversion efficiencies of BEVs and ICE vehicles, these translate to about 39 gCO₂/KM and 58 gCO₂/KM, respectively. As the grid progressively decarbonizes, this emissions advantage will grow.

The results are more complicated in the case of four-wheelers. For this vehicle segment, we modelled petrol, CNG, electric, and FCEV variants. The model is set up to approximate a mid-range private vehicle. This means that annual kilometres travelled are about 10,000, compared to a taxi or a commercial vehicle at 20,000 KM per year or more. As of 2020, both BEVs and FCEVs are estimated to have a somewhat higher TCO than the ICE versions. With the expected decline in battery costs by 2030, BEVs have a lower TCO and this gap is projected to widen by 2050. While costs for FCEV decrease, the high upfront capital costs and high operating costs (because of low conversion efficiency) mean that FCEVs are not projected to be competitive with ICE or BEV versions by 2050. In terms of carbon intensity, BEVs are lower than petrol ICEs even with today's grid emissions factor, but slightly above that of CNG four-wheelers, due to the lower carbon intensity of CNG fuel. By 2030, with the projected decarbonization of the Indian grid, this advantage flips, and BEVs are the lowest carbon option. The carbon intensity of FCEV is almost an order of magnitude above all other drivetrains in 2020, due to the high carbon intensity of grid electricity today and the low conversion efficiency of the FCEV value chain. Although this falls with the projected decarbonization of the Indian grid, and the improvement in the conversion efficiencies of electrolysis, in the **Baseline** scenario, this is not projected to be enough to make FCEVs a lower carbon alternative to ICE vehicles.

There are several factors that influence these results. First, the utilization factor is a crucial parameter. At annual utilization rates above 14,000 KM, BEVs have a lower TCO than ICE vehicles even at 2020 costs. Second, BEVs are particularly sensitive to the discount rate: a 25% increase in the discount rate from 15% to 18.75% increases the TCO of BEVs by 13%. As with BEVs, FCEVs are particularly sensitive to capital costs, utilization rate, and discount rate, but because of their fuel intensity, also to the fuel price. For example, if capital costs are 10% lower by 2050 than the **Baseline** scenario, FCEVs would be competitive with ICE vehicles. On the other hand, the carbon intensity of the electricity going into the hydrogen production process would need to be as low as 100 gCO₂/kWh for FCEVs to be a lower carbon option than ICE vehicles. It is important to stress: FCEVs are not just competing against ICE vehicles, but also against BEVs. As shown in Figure 19, BEVs are more economical and carbon efficient compared to FCEVs.

4.3.2 Heavy-duty transport: Buses and Trucks

4.3.2.1 Buses

In this section, we model a high-end electric city bus, with features such as air conditioning. We compare it with both a high-end diesel bus and a low-end diesel bus. Rather than presenting single numbers, we present the results as a set of sensitivity analyses, which highlight the drivers and tipping points. Figure 19 presents the key results.

Even at 2020 costs, the electric bus is modelled to be cost-competitive on a TCO basis with both the high-end and low-end diesel bus, under baseline assumptions of electricity tariff, discount rate, and annual kilometres travelled. However, there are a number of plausible conditions under which the electric bus becomes less competitive than the diesel bus. The key driver is the annual utilization factor: if the bus travels less than about 52,000 KM per year, it is no longer cost-competitive with the low-end diesel bus. If electricity tariffs rise above 8.5 Rs/kWh (consistent with the tariff paid by many commercial users), the electric bus is no longer competitive with the low-end diesel bus. Likewise, if the discount rate rises above 16%, electric buses are no longer effective at today's costs with ICE buses.

This analysis helps to explain why, despite successes overseas and numerous studies which suggest that BEV buses are competitive with ICE buses, the FAME II programme has not yet delivered significant deployment. High upfront infrastructure costs, reflected here in the sensitivity around the electricity tariff; high discount rates reflecting payment security concerns around state transport undertakings; technology performance uncertainty reflected in lower expected annual mileage: all of these factors can help to explain why the programme is delivering higher than expected tender results.

Nonetheless, the key point holds: with battery costs expected to more than halve by 2030, even under the worst-case scenarios, electric city buses should be competitive with ICE variants by 2030.

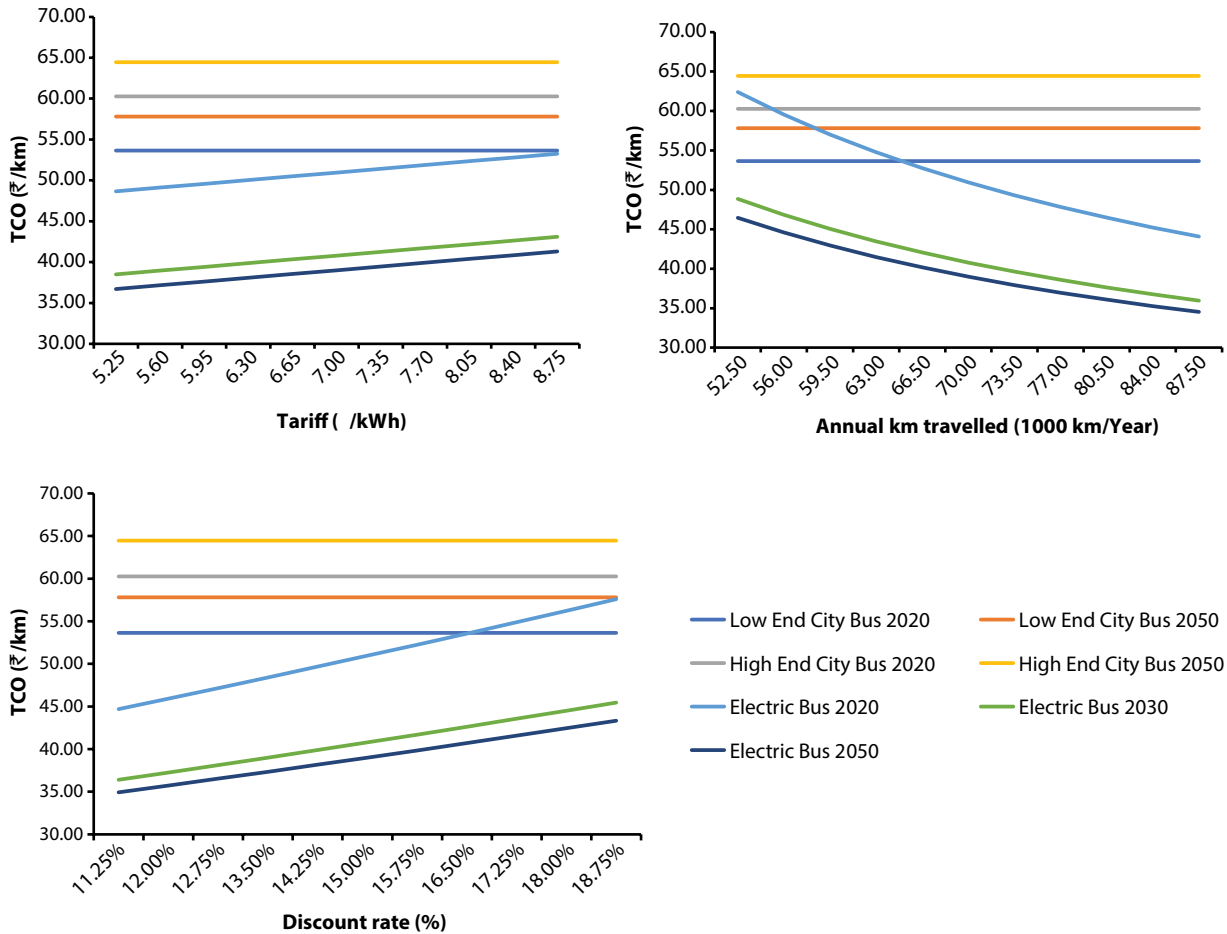


Figure 19: Sensitivity of electric city buses to electricity tariff, annual KM, and discount rate

Source: TERI analysis

Figure 20 shows the key sensitivities for FCEV city buses versus BEV buses. It shows the sensitivity of FCEV TCO to three parameters: fuel price, discount rate, and vehicle capital costs. When comparing against the EV bus, all assumptions are held constant at the baseline level. Data for the BEV bus is displayed only for 2020 and 2050 models, whereas data for the FCEV buses are displayed for all three years in the model: 2020, 2030, and 2050.

The results clearly indicate that FCEV buses are unlikely to be competitive with BEV buses in the long term. All else being equal, FCEV buses would have a slightly lower TCO than EV buses by 2050 if their fuel cost is 25% below the baseline forecast. However, the baseline forecast already includes aggressive cost reductions for fuel costs, as electrolyser costs come down. Although possible at the wholesale level, achieving a retail-level delivered cost of

hydrogen of \$1.65/kg by 2050 appears challenging, given the additional costs of transport and storage. Likewise, if capital costs are 20% lower than the baseline forecast then FCEVs may compete against BEV buses. But again, this needs to be seen in the context of already aggressive cost declines in the fuel cell and hydrogen tank storage component of capital costs in the baseline.

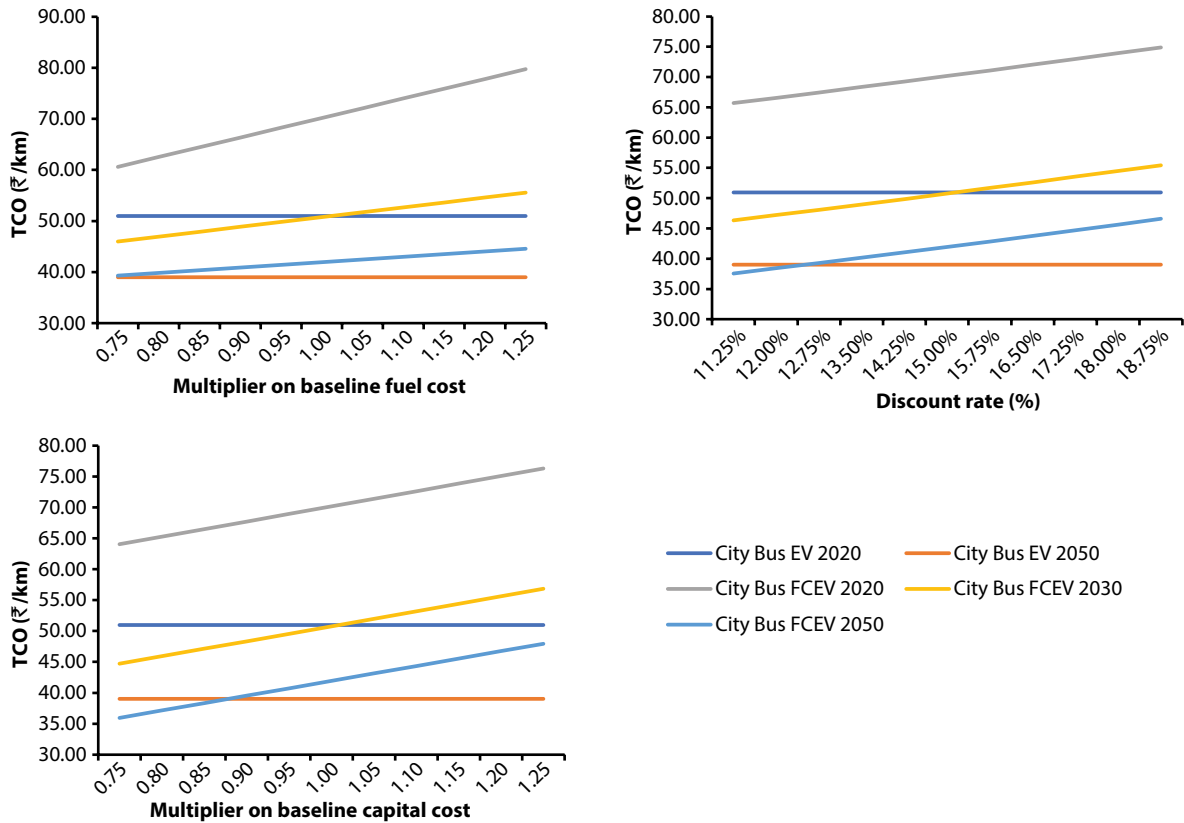


Figure 20: Sensitivity of FCEV city buses to fuel cost discount rate, and capital cost

Source: TERI analysis

For the present discussion, it suffices to note that at current costs, CNG and electric buses appear competitive with petrol/diesel buses. Plausible ‘early-adoption’ assumptions related to higher discount rates, lower usage factors, and higher fuel/infrastructure costs explain why these results for BEVs may differ somewhat from the results achieved in recent tenders. However, by 2030, the results are really unequivocal: BEV buses look extremely competitive. Assumptions on hydrogen, fuel cell, and hydrogen tank costs need to be even more bullish than our already robust assumptions for FCEV buses to have a chance at being competitive with BEV city buses by 2050, which appears unlikely.

4.3.2.2 Trucks

In this section, we assess different drivetrain costs and emissions for long-haul trucks. For this analysis, we adopt a slightly different metric to the one used earlier, namely Total Cost of Ownership / Tonne Kilometre (TCO/TKM). TKM is simply the truck payload multiplied by the distance travelled. To calculate TKM, we take the assumed payload and subtract the weight of the battery in the case of BEV trucks. The battery weight is calculated endogenously to the model, based on the assumed target range and improvements in the energy density of batteries. For the

baseline, we assume a distance of 800 KM, but also vary this as part of our sensitivity analysis. The modelled vehicle is consistent with a heavy-duty truck in the order of 25 tonnes, performing long-range interstate services for the first five years of its life, before transitioning to a lower rate of annual kilometres. As with the BEV variant, the size of the fuel cell and the hydrogen tank is determined by the assumed weight and target range of the truck.

Figure 21 shows the modelling results for trucks, with TCO and carbon intensity presented on a per TKM basis, and not on a per KM basis. In 2020, the most cost-effective option on a TKM basis is LNG trucks, due to the much lower cost of CNG per energy unit than diesel (4.04 Rs/kWh versus 6.59 Rs/kWh for diesel). This in turn is partly due to the favourable taxation of CNG versus diesel. In 2020, the estimated TCO/TKM of electric trucks is substantially above that of ICE trucks, due to the substantial weight penalty of the battery and the consequent reduction in payload. However, with the forecast reduction in battery costs and improvements in battery energy density, by 2030, BEV trucks are neck and neck with ICE trucks, and by 2050, BEV trucks could appear to be the more cost-effective option. However, the model estimates that FCEVs retail a small advantage compared to BEVs, due to the absence of weight penalty. In terms of emissions intensity, the picture does not really change between fuels, because CO₂ intensity is driven by the fundamental conversion efficiencies of the various technologies. In the short-term, the most CO₂ efficient option is CNG trucks, because the weight penalty of batteries increases the gCO₂/TKM of BEV trucks. At the same time, the grid intensity as of 2020 of around 700 gCO₂/kWh is still relatively high. The CO₂ intensity of FCEVs is an order of magnitude above that of even diesel trucks, because of the conversion losses in the FCEV value chain. By 2030, projected reductions in grid CO₂ intensity and increases in battery energy density will allow BEV trucks to overtake CNG trucks from a CO₂ intensity perspective. On the other hand, FCEV trucks can only approach the CO₂ intensity of diesel trucks by 2050, as the grid decarbonizes. This highlights the fundamental challenge for FCEVs from a climate mitigation perspective: for heavy-duty segments, the carbon intensity of electricity production needs to fall below about 250 gCO₂/kWh for FCEV trucks to represent an emission saving compared to diesel trucks.

Figure 22 shows the key sensitivities of BEVs versus FCEV trucks. Only two of these sensitivities appear to have the potential to change the picture seen in Figure 21 for 2050. If the target range is reduced to below 500 KM, the required battery size reduces and along with it the weight penalty. This means that for short-haul heavy-

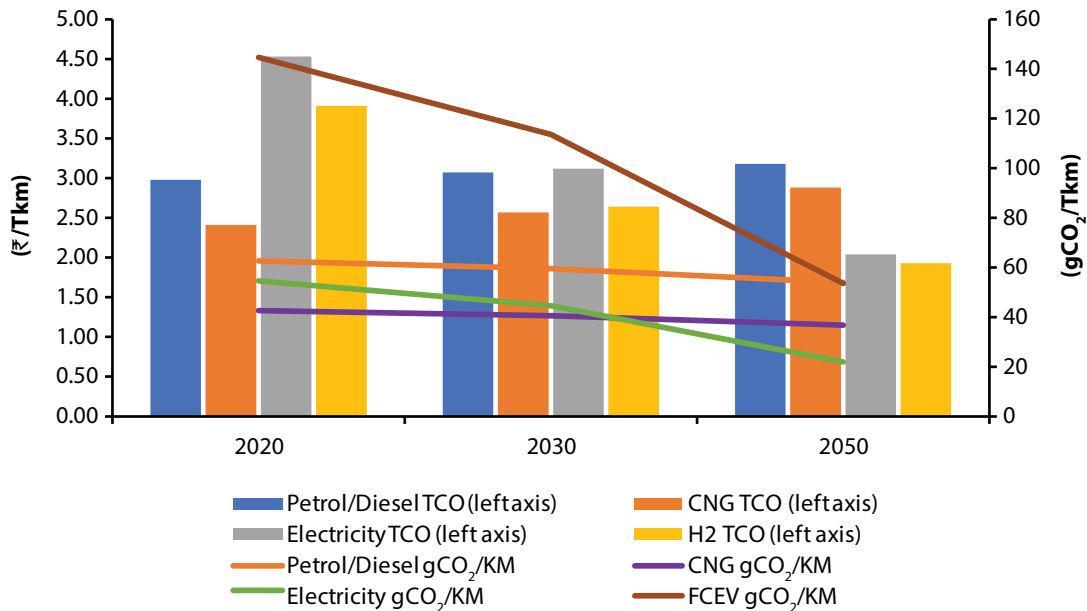


Figure 21: Modelled results for TCO/TKM and carbon intensity (gCO₂/TKM)

Source: TERI analysis

duty transport (mine and construction site, waste collection, etc.), BEVs are likely to be competitive with FCEVs. Likewise, if the fuel price of FCEV turns out to be higher than projected by as little as 15% (\$2.5/kg instead of 2.2), then BEV trucks would have a lower TCO/TKM. This scenario is entirely possible given the aggressive cost reductions required to reach a target of \$2.2/kg for delivered hydrogen, including transport and storage.

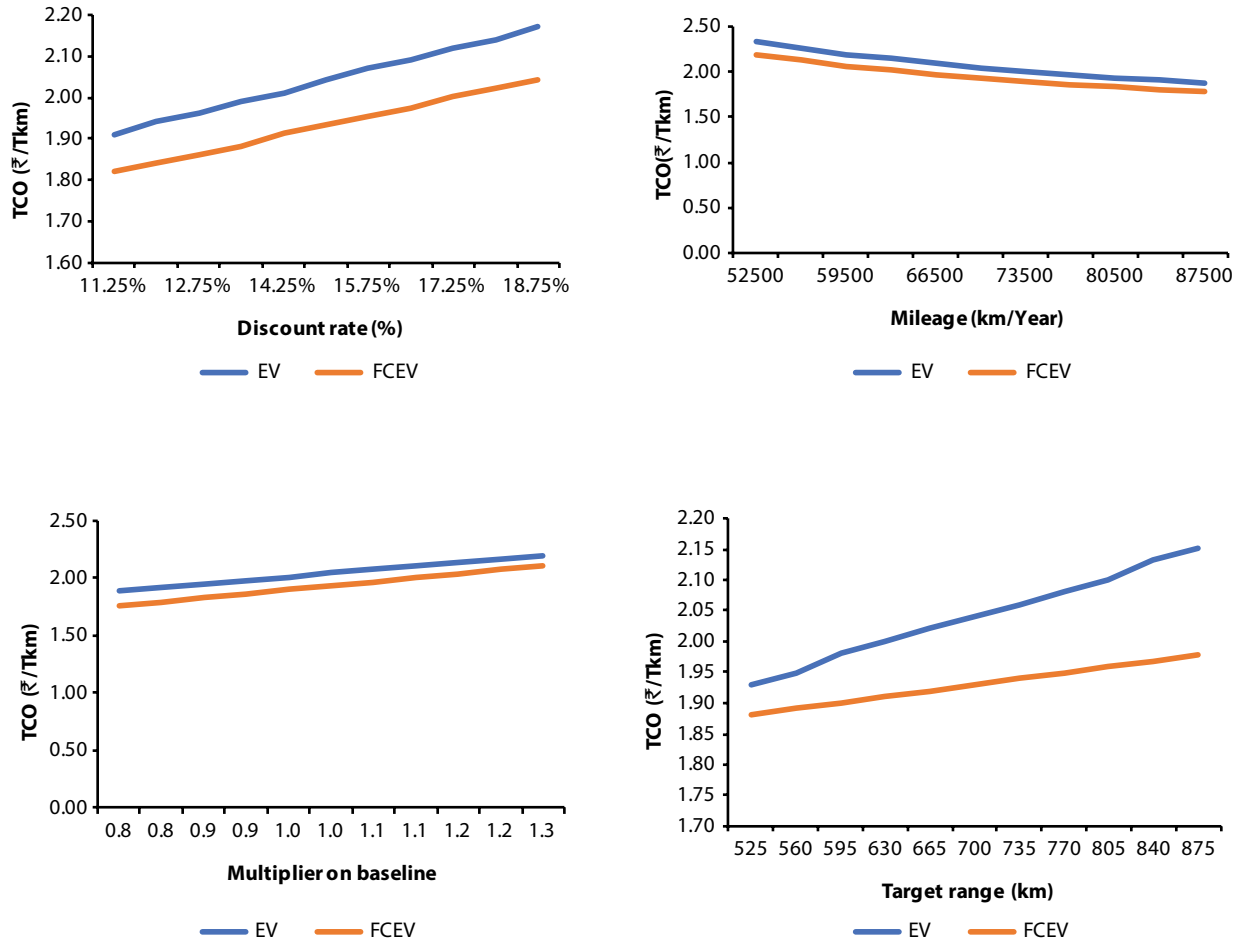


Figure 22: Key sensitivities of FCEV versus BEV trucks

Source: TERI analysis

4.3.2.3 Conclusion and Multi-criteria Assessment

As discussed in Section 4.3.1, TCO is only one metric on which future transport scenarios will be determined. As a result, we have produced multi-criteria assessments for two sub-sets of the transport market: the lighter passenger vehicles, where BEVs will dominate, and the heavier-duty, longer-distance vehicles, where FCEVs could play a role (Table 9). This has been undertaken using the available literature and stakeholder engagement with experts in the transport sector.

Table 9: Multi-criteria assessment for light passenger vehicles

	ICE	Electric	Hydrogen
TCO	Loses competitiveness to BEV before 2030	Higher usage segments competitive today, all to be competitive before 2030	Not competitive over the time period
Refuel / charging time	15mins	30mins+	15mins
Infrastructure requirements	Already in place	New high capacity charging network	New hydrogen refuelling stations
User acceptability	No change	Change to refuelling behaviour and fleet operation	Minimal change
Weight penalty of drivetrain + storage	Minimal	Minimal	Minimal
Risks	Crude oil prices and fuel taxes	Minimal: confident in cost declines of batteries	Dependent on cost declines in fuel cells, tanks, and electrolyzers

Source: TERI analysis

Table 10 sets out a number of important criteria, alongside the TCO, all of which have an important bearing on the take-up of alternative drivetrain vehicles. These include refuel / charging time, infrastructure requirements, user acceptability, weight penalty, and other risks. Whilst we can be confident that BEVs will compete from a cost perspective, other barriers including new charging networks, which will be especially challenging to deliver for India's rural population, will limit the pace of transition. There will also be a change in behaviour required from users, who will either need to charge at home or place of work, or plan additional time to charge at public stations. For certain users, this may well represent an improvement on today's experience, if home charging is possible. However, this will not be the case for everyone due to limited off-street parking.

Table 10: Multi-criteria assessment for heavy-duty trucks and inter-city buses

	Diesel	Electric	Hydrogen
TCO	Not competitive post 2030	Competitive for shorter distances post 2030. Potentially competitive across all relevant distances by 2050.	Competitive over longer distances
Refuel / charging time	15mins	2hrs+	15mins
Infrastructure requirements	Already in place	New high capacity charging network	New hydrogen refuelling stations
User acceptability	No change	Change to fleet operation required	Minimal change
Weight penalty of drivetrain + storage	Minimal	Significant for long distance	Minimal
Risks	Crude oil prices and fuel taxes	Minimal: confident in cost declines of batteries. Some uncertainty about pace of improvement in battery energy density.	Dependent on cost declines in fuel cells, tanks, and electrolyzers

Source: TERI analysis

For the heavier-duty and longer-distance segments, such as trucks and inter-city buses, we have undertaken a similar assessment. Whilst the TCO analysis suggested close competition between BEVs and FCEVs over the longer term, the pace of adoption in these segments will depend on reducing recharging time, rolling out high capacity charging, raising awareness with fleet operators, and reducing the weight penalty of batteries (via improving energy density). Aside from a new hydrogen refuelling network, FCEVs would be more competitive in these areas, due to faster refuelling times and the similar operation of an FCEV truck or bus versus a diesel equivalent.

The overall impression that emerges from this analysis is that the heavier-duty and longer-distance vehicle segments will likely decarbonize through a mixture of direct electrification (BEVs) and indirect electrification (FCEVs):

- BEVs are likely to be highly competitive in sectors where daily utilization rates are less than 500 KM, and routes are highly predictable to allow programming of lengthy charging periods. These include waste disposal, commuter bus routes, service vehicles, etc.
- FCEV trucks may be a preferred option for longer routes above 500 KM, although competitiveness of FCEVs is dependent on robust cost declines in multiple technologies and very low delivered costs of hydrogen. Likewise, for net emissions reductions to be achieved, either open access low carbon sources of generation are required, or the electricity grid emissions must reduce by roughly a factor three from today's level.
- CNG trucks appear useful as a potential bridging option, but care must be taken about locking in investment and infrastructure.

Overall, the assessment suggests that both BEVs and FCEVs have a role to play in low-carbon heavy-duty transport, although the priority must be to electrify first and deploy FCEVs only for those segments within heavy-duty transport where BEVs are not viable.

4.4 Other Transport

There are also a couple of other important transport segments that could make use of low carbon hydrogen to reduce emissions over the longer term, namely shipping and aviation. Research and analysis in segments outside road transport are at a relatively early stage in India, and elsewhere. As such, we only provide a summary of the current landscape and a qualitative assessment of the potential role of hydrogen in this report.

4.4.1 Shipping

The shipping industry emits around 940 MtCO₂ per year contributing to around 2.5% of global GHG emissions. The International Maritime Organization has set a target of reducing emissions from shipping by at least 50% by 2050 compared to 2008 levels (IMO, 2014). This will require new technologies and fuels to power ships. Shipping supply chains would also require the necessary infrastructure to distribute new fuels, including storage tanks, liquefaction, and regasification plants.

The two leading low carbon fuel options for decarbonizing shipping is a switch to either green ammonia, or to green methanol, with more focus on green ammonia to date. The Energy Transitions Commission (ETC) in their recent report set out the need for full value chain pilots to prove the end-to-end economic case for using these new fuels. This would require bringing together fuel producers, bunkering suppliers, regulators, ship builders, vessel operators and owners, cargo owners, financial institutions, and governments (ETC, 2020).

A Danish consortium of shipping and logistics companies and energy providers (Maersk, DSV Panalpina, DFDS, SAS, and Ørsted) have joined together to set up a hydrogen production and hydrogen-derived synfuels facility in

Denmark by 2023, including green ammonia for shipping. The project is expected to deliver more than 250,000 tonne of hydrogen for buses, trucks, maritime vessels, and airplanes every year by 2030 (Maersk, 2020).

In India, shipping accounts for only 6% of freight transport, reaching 9 Mt of freight annually. However, coastal shipping is expected to increase significantly in the coming years, as well as greater use of inland waterways to reduce pressure on road and rail freight. The roll on-roll off (Ro-Ro) ferry service launched in Gujarat in 2017 is one such initiative, with plans to expand nationwide. The current project, costing Rs. 615 crore, facilitates vehicle and passenger ferry services between Dahej and Gogha across the Gulf of Cambay (The Times of India, 2020). A similar service is expected to be introduced between Mumbai and Mandwa (Mumbai Live, 2020).

The use of hydrogen-powered fuel cells for smaller ferries is well understood, although they are yet to be deployed in larger, merchant vessels. In any case, heavy freight shipping is likely to use a more energy-dense hydrogen-derived synfuel, like ammonia. The use of fuel cells in ferries is already being trialled in several locations around the world, with multiple successful pilot projects throughout the 2010s. Fuel cells are sometimes operated with other fuels including methanol, natural gas and diesel fuel, which are converted into hydrogen using internal or external reformers (DNV GL, 2017).

The main challenges remain the cost of hydrogen, as well as the cost of the fuel cell stack and power train, which are still costlier than diesel equivalents. For India, as elsewhere, new refuelling infrastructure would need to be constructed, taking into account large-scale hydrogen storage (FICCI, 2019). These challenges must be overcome before the technology can be adopted in India.

4.4.2 Aviation

Decarbonizing the aviation sector is a major challenge given that the quantity of emissions is already large and growing rapidly. The total CO₂ emissions from all commercial operations totalled 918 MtCO₂ in 2018, equivalent to 2.4% of global emissions. This represents a 32% increase over the past five years (ICAO, 2019). The International Civil Aviation Organization (ICAO) has set out two goals for the international sector. First, carbon neutral growth from 2020 onwards and second, a 2% annual efficiency improvement out to 2050. To achieve these aspirations, it is pursuing various measures including aircraft technology improvements, operational improvements, sustainable aviation fuels, and market-based measures (ICAO, 2019).

Hydrogen is a potential option to significantly reduce emissions from aviation, putting the sector on track to meet their own targets of a 50% reduction in CO₂ emissions by 2050, versus 2005 levels. Hydrogen can either be used directly in fuel cells for shorter-haul flights or as an input to synthetic hydrocarbon jet fuel for long-haul flights, which would be the majority of demand.

Sustainable aviation fuels (SAF), such as synthetic jet fuels using green hydrogen, are currently more expensive than fossil-based jet fuel, preventing their large-scale adoption. With expected cost declines in green hydrogen production, alongside supportive policy, this gap can be reduced, increasing SAF uptake. One significant advantage of adopting SAF is their ability to make use of existing jet fuel equipment and infrastructure, easing the transition (WEF, 2020).

For shorter-haul flights, CSIRO analysis indicates that hydrogen fuel-cell alternatives can begin to replace current equipment within the next five years (CSIRO, 2020). One start-up, ZeroAvia, is planning commercial flights for smaller aircraft (10–20 seats) in the next three years. They also claim that hydrogen will not only reduce emissions but it also has the potential to become cost-competitive with conventional fuels, through reducing operating costs (Emerging Tech Radio, 2020).

The main challenges to the rapid adoption of hydrogen in this sector remain reducing the weight of the tanks and fuel cell systems, storage and distribution of liquid hydrogen within the aircraft, development of turbines capable of burning hydrogen with low nitrous oxide emissions, and the development of efficient refuelling technologies that can match flow rates of kerosene. However, none of these barriers are insurmountable, and we can expect progress on demonstrating hydrogen aircraft to be achieved within the next decade (E4tech, 2019). Large storage volume and redesign would be needed for pure hydrogen, and so hydrogen-derived synfuels and biofuels could be more attractive in this sector. Although synfuels, such as synthetic kerosene are currently 4–6 times more expensive than kerosene, costs are expected to reduce by 50% in the next decade.

In India, the main focus for hydrogen in the aviation sector has been the use of hydrogen vehicles for ground handling vehicles to improve local air quality (Ministry of Civil Aviation, 2016). To date, more of a focus has been on blending biofuels with kerosene, with Spicejet leading the way on such an initiative. They used 25% biofuel on one of their flights between Dehradun and Delhi (The Statesman, 2018). As with all biomass use, the extent to which this can be scaled-up for the aviation sector as a whole will be limited by sustainable biomass availability.

4.5 Demand Scenarios

4.5.1 Introduction

Having analysed the various factors that may determine the speed and direction of a road transport transition in India, and the role of hydrogen therein, we now turn to the development of long-term scenarios for the road transport sector out to 2050. To do so, we develop a detailed stock model of the Indian vehicle fleet out to 2050. Growth in the total number of vehicles is determined by the growth in GDP per capita. For each vehicle type, growth curves have been defined based on historical data from (MoRTH, 2019), and cross-country data regarding relationships between income and per capita vehicle ownership. Assumptions around vehicle lifetime are then used to derive annual entries and exits from the total stock of vehicles. Entries are the sum of net growth in the total stock plus replacements for retiring vehicles. Retiring vehicles are those that have reached the end of their assumed technical lifetime.

For each annual ‘vintage’ of new additions to the stock, assumptions are made regarding the improvement in energy efficiency as well as the penetration of alternative drivetrains in new sales. In this way, the composition of the stock and its aggregate energy efficiency change only slowly, as new vehicles enter and old vehicles are retired. This allows us to model the possible pathway for the growth in alternative drivetrain vehicles in a detailed and realistic manner, as changes in the curves for the composition of new sales and stock retirements gradually change the composition of the stock itself.

We define the curves for new drivetrain sales in the following way. First, we have surveyed both the quantitative economic information regarding the economic competitiveness of different drivetrains in different vehicle segments, as well as the multi-criteria quantitative and qualitative information gathered in Table 10. Second, the transition is likely to be driven by a combination of endogenous factors, notably the growing economic competitiveness of EVs, and exogenous factors, notably the policy required to translate pure economic competitiveness into a practical advantage through the development of enabling infrastructure. For this reason, we model two contrasting scenarios. In the **Baseline** scenario, the transition to alternative drivetrains is assumed to proceed more slowly, and be driven by the inherent economic competitiveness of particular drivetrains and policy of modest strength to enable transition. In the **Low Carbon** scenario, policy is assumed to be more stringent, and the transition to be consequently both faster and deeper. Third, we have also been informed by the forecasts of others, for example (BNEF, 2020).

Tables 11 and 12 display the assumptions in the **Baseline** and **Low Carbon** scenarios. Several caveats should be noted when interpreting these tables. The available data is not sufficiently granular to allow a precise breakdown of the composition of the bus fleet between city and inter-city buses, or bus sizes; likewise, data is not granular enough to allow a breakdown of trucks by size or duty pattern. Assumptions taken regarding the penetrations of BEVs or FCEVs in these segments should therefore be seen as ‘educated guesses’ regarding the possible market share within these segments that could be amenable to alternative drivetrain penetration, based on the policy storylines driving each scenario. In this vein, the scenarios should be seen as just that: not forecasts, but plausible and internally consistent storylines for exploring the consequences of contrasting assumptions. The key message emerging from our analysis above is twofold. First, although direct electrification appears preferable from multiple perspectives, it appears unlikely that there will be one technology paradigm for heavy-duty transport. Second, the multi-criteria assessment highlights how much of the pathway is policy-determined, notably with regard to infrastructure investment. These scenarios should be understood as exploring two different policy storylines.

Table 11: Share of alternative drivetrains in new sales in the Baseline scenario

	Two Wheelers	Four Wheelers		Buses			Trucks		
	BEV Share in New Sales	BEV Share in New Sales	NGV Share in New Sales	BEV Share in New Sales	NGV Share in New Sales	FCEV Share in New Sales	BEV Share in New Sales	NGV Share in New Sales	FCEV Share in New Sales
2030	17%	12%	15%	15%	15%	0%	4%	14%	0%
2040	59%	52%	12%	44%	14%	2%	16%	12%	1%
2050	69%	68%	6%	50%	10%	10%	20%	9%	5%

Source: TERI analysis

Note: BEV = Battery electric vehicles, FCEV = Fuel cell electric vehicle, NGV = Natural gas vehicle.

Table 12: Share of alternative drivetrains in new sales in the Low Carbon scenario

	Two Wheelers	Four Wheelers		Buses			Trucks		
	BEV Share in New Sales	BEV Share in New Sales	NGV Share in New Sales	BEV Share in New Sales	NGV Share in New Sales	FCEV Share in New Sales	BEV Share in New Sales	NGV Share in New Sales	FCEV Share in New Sales
2030	36%	28%	10%	23%	9%	0%	12%	14%	1%
2040	88%	84%	7%	65%	8%	3%	43%	11%	9%
2050	97%	94%	1%	74%	5%	13%	54%	6%	27%

Source: TERI analysis

Note: BEV = Battery electric vehicles, FCEV = Fuel cell electric vehicle, NGV = Natural gas vehicle

4.5.2 Results by Fuel

Figure 23 shows the results of the model by fuel in the and **Low Carbon** scenarios. We use the energy unit TWh, converting non-electrical fuels into TWh based on their energy content. In the following text, we occasionally also quote results in million tonnes of oil equivalent (Mtoe) in parentheses for readers more familiar with this unit in the transport context.

In the **Baseline** scenario, total transport demand is projected to grow to 3,150 TWh (270 Mtoe) by 2050, an increase by a factor 2.7 on the historical level. Even in the **Baseline** scenario, passenger demand for petrol and diesel could peak by 2034, as ICE efficiency improvements and the growth of BEVs eat into diesel and petrol demand. On the other hand, petrol and diesel demand for freight transport continues to grow across the whole projection period, as the penetration of BEVs, FCEVs, and NGVs is not sufficient to halt the growth of diesel and petrol. This highlights the importance of the future of freight transport to India’s oil product demand growth. Even in the **Baseline** scenario, however, total oil product demand growth is far more subdued than it has been historically, growing by only a factor 1.9 between 2020 and 2050, held back by ICE efficiency improvements and the accelerating transition in light-duty transport. The total petrol and diesel consumption is projected to reach 2,150 TWh (185 Mtoe) by 2050.

Total electricity demand in transport would reach 540 TWh by 2050, a substantial amount compared to the 2018 level of total final consumption of electricity across all sectors of 1,200 TWh (IEA, 2020). This growth is largely driven by the passenger segment. Hydrogen demand is expected to reach just 59 TWh by 2050, as penetration is assumed to be negligible in light-duty transport, and modest in heavy-duty freight and passenger transport. Natural gas demand would reach 400 TWh.

In the **Low Carbon** scenario, the total transport energy consumption is restricted to 2,250 (194 Mtoe). This is due to the assumed faster rate of energy efficiency improvement in ICE vehicles, particularly in buses and trucks. It is also driven by the faster transition to BEVs, whose far higher conversion efficiencies allow the same transport service demand to be met with far lower final consumption of energy. Passenger demand for diesel and petrol would peak around 2030 and begin a rapid decline thereafter. The shorter stock lifetime of two-wheelers and four-wheelers allow for a faster stock transition, once the penetration of BEVs in new sales reaches an appreciable level.

On the other hand, freight demand for petrol and diesel peaks later and declines more slowly. This is because BEVs and FCEVs are assumed to penetrate the stock later and more slowly, and the change of stock composition is delayed by the assumed longer lifetime of heavy-duty vehicles. Total 2050 petrol and diesel demand across both passenger and freight is only 5% higher than the 2020 level, and 40% lower than the maximum level reached in 2032. The total electricity demand rises to 990 TWh, indicating the extent to which the growth of BEVs could be a substantial source of electricity demand growth (see Section 6 for full projections for 2050 electricity demand

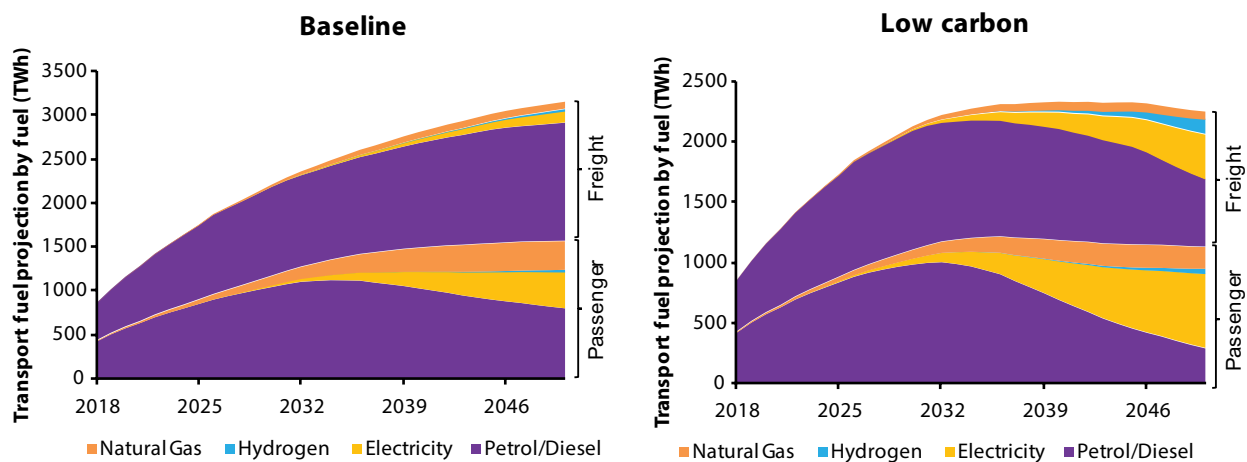


Figure 23: Transport fuel projection by fuel (TWh)

Source: TERI analysis

across all sectors). Even in the **Low Carbon** scenario, hydrogen demand is a relatively modest share of total transport energy consumption, reaching just 168 TWh. This is because electricity is assumed to be the preferred fuel in buses, while FCEVs penetrate relatively late in the projection in the heavy-duty truck segment. The longer-lifetime and slower net stock growth of trucks means that the 2050 stock composition still contains some ICE vehicles as well as a rapidly growing share of BEVs and FCEVs.

4.6 Conclusion

This section has examined the role of hydrogen in the transport sector, allowing us to draw a number of conclusions. First, it is important for policy to consider the entire value chain of fuel production and consumption. FCEVs are relatively inefficient when the fuel value chain is considered. Given that low carbon electricity is a precious resource, direct electrification should be the priority wherever possible. Indeed, because of the low conversion efficiencies of the fuel value chain, FCEVs are not a low carbon option except at very low emissions intensities of electricity production. This is in contrast with BEVs, where the very high conversion efficiencies of BEV technology allow BEVs to be a lower carbon transport option than ICEs already at today's grid emissions factor. Second, based on current technology trends, BEVs are already competitive with ICEs in numerous segments, and likely to become so in the remaining segments within the next decade, with the exception of long distance, heavy-duty freight, and passenger transport. Third, this conclusion is tempered somewhat by a multi-criteria assessment of non-cost factors. For BEVs to penetrate, they will require infrastructure, changes in business models, as well as continued incentives to overcome higher costs and the technology risk premia associated with a novel technology. While some degree of transport transition is inevitable, its speed and depth will depend on supportive policy. Fourth, even in the heavy-duty transport, there is unlikely to be a single technological paradigm driving the low carbon transition. BEVs will be competitive in heavy-duty segments with regular, predictable routes and shorter daily duty cycles (less than ~500 KM, perhaps rising to less than ~700 KM by 2050). This is still a substantial share of the heavy-duty market. The role of FCEV will probably be limited to very long-distance, heavy-duty transport. Given its limited market share, the per unit costs of the requisite infrastructure risk is high. Supporting infrastructure development and optimization to keep costs low appears to be a crucial task for future policy.

5

INDUSTRY



Key messages

- Industry is the largest consumer of hydrogen today and will continue to be so as demand for hydrogen grows across industrial sub-sectors out to 2050.
- In the Baseline scenario, low carbon hydrogen will start to play a marginal role in the ammonia, refinery, and steel sectors after 2030.
- In the Low Carbon scenario, with greater policy support and faster cost reductions, we can expect low carbon hydrogen to start being deployed from 2025.

5.1 Introduction

Industry is currently the dominant user of hydrogen both in India, and globally. Most hydrogen is currently used in four sectors: fertilizers, refineries, petrochemicals, and methanol. In India, the vast majority of methanol is imported, leaving the dominant sectors for hydrogen use as fertilizers and refineries, constituting approximately 50% of the demand each. In future, these sectors will continue to grow to satisfy the demands of a rapidly growing country, requiring more hydrogen. For these industries, it will be important to ensure new demand is met through low carbon sources, wherever possible.

There are also a number of new sources of hydrogen demand, where hydrogen is not currently used today. The main sector of interest is iron and steel, where hydrogen has the potential to replace coking coal, non-coking coal, and natural gas, depending on the production route. Since the iron and steel sector represents the largest industrial sector, the potential growth in hydrogen demand from this new use is significant.

Beyond the steel sector, there is also the potential for hydrogen to replace fossil fuels as a source of industrial heat. Today, in India, heat is generated by coal, oil or natural gas in a number of industries, including cement, bricks, food processing, forging, and many others. The optimal route for decarbonizing industrial heat is electrification, as this uses less energy than hydrogen. However, where this is not possible, hydrogen could be a viable option.

In terms of a methodology for assessing the potential role of hydrogen in key industry sectors, we follow the steps below:

- Model material production and consumption scenarios out to 2050
- Assess the cost-competitiveness of hydrogen versus the main incumbent production routes
- Based on this assessment, assume a start point and growth rate for low carbon hydrogen to produce a **Baseline** scenario
- Assume a series of more ambitious policies and faster technology development to develop a **Low Carbon** scenario
- Arrive at a final estimate for fossil-fuel and low carbon hydrogen demand over this time period for the two scenarios

5.2 Ammonia

5.2.1 Background

The fertilizer industry in India currently consumes a large amount of fossil fuels, principally natural gas. This is used to produce ammonia, which is the main intermediary for providing nitrogen in all nitrogen-containing fertilizers. This can be used directly (only nitrogen) or as a complex fertilizer (one or more nutrients in addition

to nitrogen). Urea is the main nitrogenous fertilizer, with various grades of complex fertilizer having different nitrogen content. Diammonium phosphate (DAP) is the most commonly used complex fertilizer in India.

The Indian fertilizer industry is amongst the most efficient in the world, which is due to a near complete shift to natural gas-based processes in the 1980s and 1990s as well as additional technology upgrades. Two plants also currently use naphtha as an input feedstock due to lack of connectivity to a natural gas pipeline. A new coal to ammonia plant is also being constructed at Talcher, Odisha. Use of this technology in future plants will depend upon the performance of this plant once it is commissioned.

Further emissions reductions will require more significant changes to the production of ammonia. This could include ensuring that the hydrogen feedstock used for fertilizers is low carbon, either through adopting carbon capture, and storage technologies (blue ammonia) or by using renewable electricity to produce green hydrogen (green ammonia).

To assess the potential role of hydrogen in a future low carbon India, we have produced demand projections for ammonia in the fertilizer industry, as well as estimates for how much hydrogen would be required. We have also undertaken cost analysis for low carbon options.

5.2.2 Demand

To understand the scale of potential demand for hydrogen within the fertilizer sector, it is important to assess historical and projected fertilizer production and consumption. Historical data for fertilizer production and consumption was collected from the Department of Fertilizers annual reports (Ministry of Chemicals and Fertilizers, 2020). For future projections, we have used data (Figure 24) provided by the Fertilizer Association of India (FAI), which was verified by our own econometric analysis using assumptions around GDP growth (FAI, 2020).

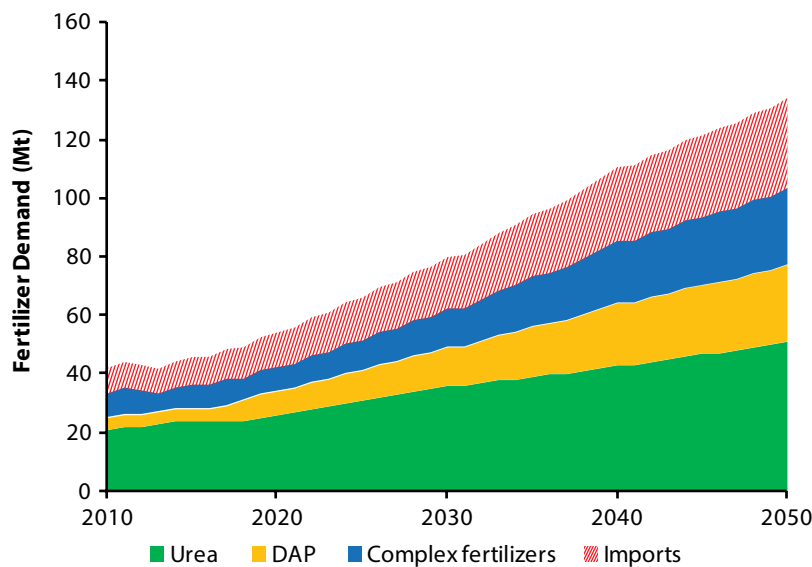


Figure 24: Demand for fertilizers – domestic production and import, 2010–2050

Source: (Ministry of Chemicals and Fertilizers, 2020); (FAI, 2020)

Fertilizer consumption is expected to increase from around 45 kg per capita today to 75 kg per capita by 2050. The IEA estimates that demand for fertilizers saturates at around 85–135kg per capita (IEA, 2018). It is worth noting that there are large uncertainties in future demand for fertilizers, particularly in the context of policies encouraging ‘zero-budget’ natural farming. This is a method of chemical-free agriculture, using traditional practices, which

has some level of political support (The Hindu, 2019). It is also important to highlight the current skew towards nitrogen-based fertilizers in India (such as urea), which is driven by the subsidy support for these products.

It is clear that demand for fertilizer products will increase rapidly out to the mid-century but to understand hydrogen requirements for India, it would require us to also project the share of this demand that will be met by domestic production. India currently imports 25–30% of fertilizers but we assume this would continue to fall steadily over time. Based on expert inputs, we assume that the share of urea falls over time, being replaced by DAP and other complex fertilizers.

In line with the growing demand, production is also expected to double, from around 40 Mt today to 90 Mt by 2050. As demand for urea falls in relation to other fertilizer products, domestic production can satisfy a greater share of domestic demand. We assume domestic production would increase from approximately 75% of demand in 2020 to 90% by 2050. Today, approximately half of DAP and complex fertilizer products are imported. This is expected to fall slightly to around 40% imports by 2050, as domestic manufacturing capacity ramps up.

To calculate hydrogen demand from fertilizer production, we estimate the ammonia requirements for each sub-category, before converting this to hydrogen requirements (Table 13).

Table 13: Ammonia and hydrogen requirements for different fertilizer products

	Urea	DAP	Other CF
kgNH ₃ /t	570	230	240
kgH ₂ /tNH ₃	180		

Source: (FAI, 2020)

We estimate that around 3 Mt of hydrogen is in demand by the Indian fertilizer industry today, which is over 50% of India's total hydrogen demand. By 2050, this could increase to around 7.5 Mt under a business-as-usual scenario, assuming growth in fertilizer production as outlined previously (Figure 25).

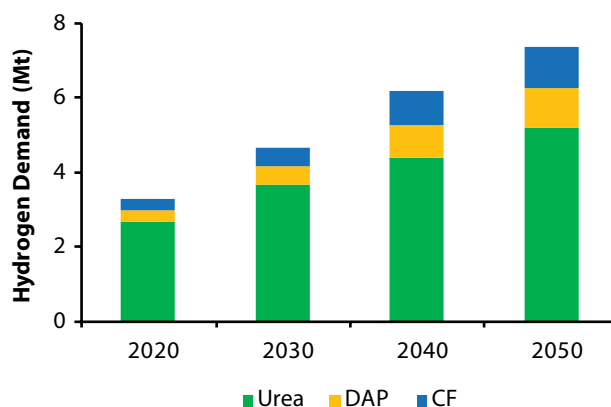


Figure 25: Hydrogen demand in the fertilizer sector, 2020–2050

Source: TERI analysis based on (FAI, 2020)

5.2.3 Low-carbon Options

Decarbonizing the production of ammonia in the fertilizer industry would require producing the hydrogen from green or blue sources, as the hydrogen production constitutes the bulk of CO₂ emissions in the process. As

explored in Box 4, the adoption of CCUS infrastructure in India is highly uncertain, although it does have the potential of being retrofitted to existing plants to accelerate the decarbonization of the sector. The principal method for reducing emissions from the sector, particularly for new capacity, would be the use of water electrolysis to produce the hydrogen required for ammonia.

Table 14: Commercial and pilot plants using green H₂ for NH₃ production

Company / Organization	Country	Opening date	Ammonia capacity
Siemens	UK	2018	30 kg/day
SIP Energy Carriers	Japan	2018	20 kg/day
Yara & Engie	Australia	Early 2020's	80 tonne/day
Proton Ventures	Netherlands	Early 2020's	20 kt/year
Thyssenkrupp	Australia	2020	50 tonne/day
Haldor Topsoe	Denmark	2025	N/A
NEOM & ACWA Power	Saudi Arabia	2025	1.2mn tonne/year

Source: (BNEF, 2019)

Today, there are a number of trial projects looking at incorporating water electrolysis into ammonia production in order to reduce emissions from the fertilizer industry. Most of these are relatively small in scale, with only the Yara and Engie, NEOM and Thyssenkrup sites approaching commercial scale. It's worth noting that these two sites are based in Australia, which, like India, has access to large amounts of high-quality solar resource.

In our analysis, we assess the costs of electricity required for the electric route to become competitive with the natural gas route. The fertilizer sector currently has access to pooled natural gas prices, which combine imported and domestic natural supplies to provide a lower price. The current pooled gas price is approximately \$8/mmbtu, which is reflected in our range of prices at \$6–10/mmbtu. Figure 26 shows the cost comparison for plants operating at 95% utilization, with the electricity therefore needing to be provided via the grid or 'round-the-clock' renewables projects.

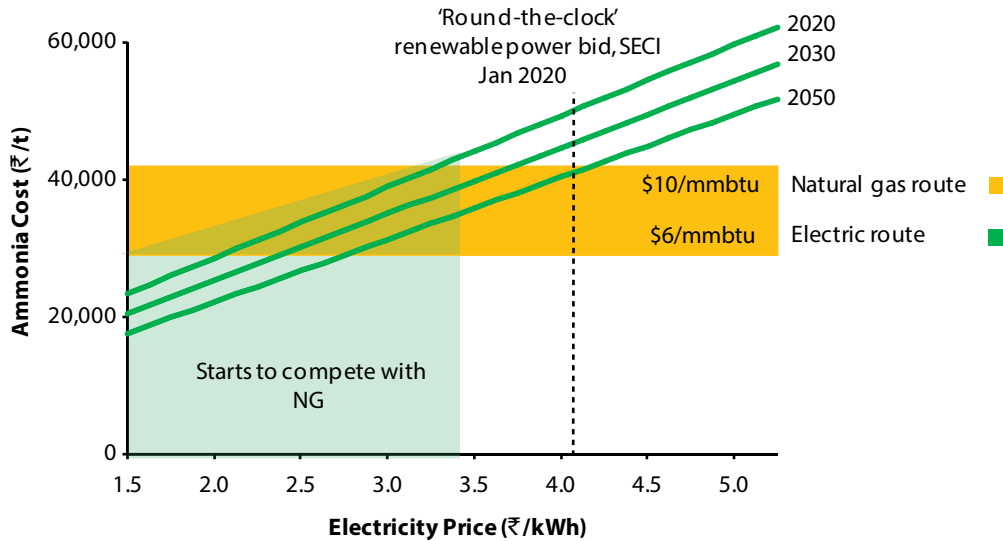


Figure 26: Costs of ammonia production – electric vs. gas route

Source: TERI analysis based on (IEA, 2019)

Based on this analysis, electricity prices would need to be between Rs. 3.3/kWh and Rs. 2.0/kWh for the electric route to become competitive in 2020. Below Rs. 2.0/kWh, the electric route will be consistently cheaper than the gas route. By 2030, electricity prices would need to be Rs. 3.6/kWh to start competing with NG. Whilst costs of grid electricity for industrial consumers are considerably higher (Rs. 5.5–6.5/kWh), round-the-clock renewables projects could soon start to provide electricity at these prices, with the Solar Energy Corporation of India (SECI) recently awarding a tariff of Rs. 4.0/kWh in January 2020.

The cost estimates in Figure 26 assume an electrolyser in near constant operation at 95% utilisation. It is possible that alternative models of variable electrolyser operation, larger hydrogen storage, and renewable electricity could be more cost-effective, being able to take advantage of cheaper electricity costs.

Figure 27 shows a comparison of these routes, assuming 2030 costs and efficiencies for both electrolysis and natural gas. It is clear how the cost of electricity dominates the costs of production for the high utilization modes of operation – grid electricity and round-the-clock renewables. Even with lower costs of electricity from round-the-clock renewables projects, it may be challenging for the electric route to compete on this basis.

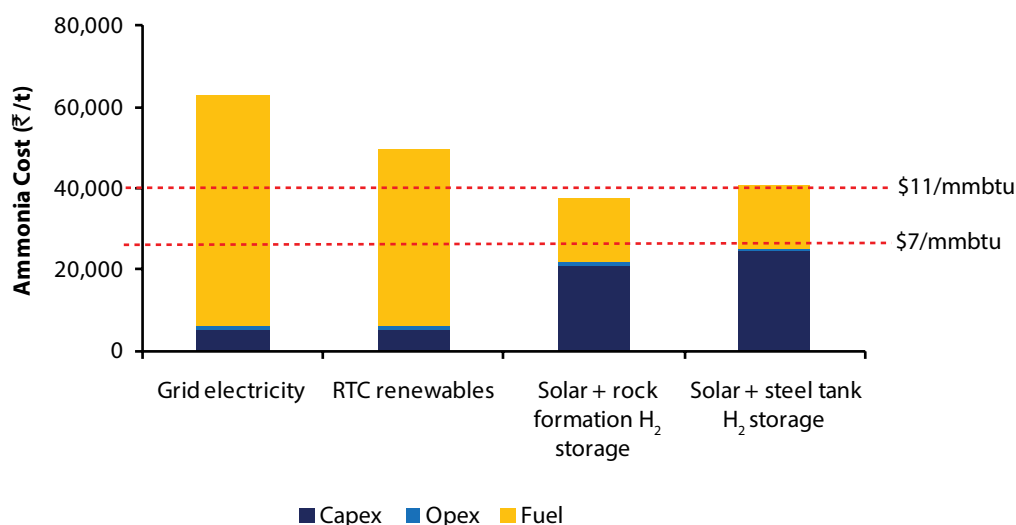


Figure 27: Cost of ammonia production from different modes of operation, 2030

Source: TERI analysis based on (IEA, 2019)

An alternative mode of operation is to pair an electrolyser directly with a renewable electricity resource, such as solar. This would mean that the electrolyser could access electricity prices of approximately Rs. 1.6/kWh in 2030. However, the solar output is not consistent at an assumed average load factor of around 28% by 2030. As the Haber-Bosch process needs a continuous supply of hydrogen, the solar and electrolysers would need to be oversized and paired with hydrogen storage to ensure that the plant could receive a near constant supply of hydrogen. However, some producers have expressed a willingness to build in some Haber-Bosch flexibility which can go a long-way in reducing hydrogen storage requirements. In Figure 27, we show the cost impact of such a set-up, whereby the increased capital costs of electrolysers and hydrogen storage are more than offset by the reduced cost of electricity. This would allow green ammonia plants in optimal locations to produce ammonia at prices that would be cost-competitive with natural gas.

5.2.4 Barriers to a Low-carbon Transition

Whilst it appears as though the costs of green ammonia production are set to compete with the natural gas-based route by 2030, there are a number of barriers which may inhibit the rate of transition.

5.2.4.1 CO₂ Requirements for Urea

The dominant fertilizer product used in India today is urea, constituting around 60% of fertilizer demand (Ministry of Chemicals and Fertilizers, 2020). The production of urea (CH₄N₂O) requires the addition of one carbon dioxide molecule to two ammonia molecules, which means an external carbon source is required. For the natural gas route, CO₂ is recovered from the reformation process and recycled for urea production. However, for a switch to green ammonia, an additional CO₂ source would be required. In the short to medium term, a solution could be to add electrolyzers to existing natural gas plants, to expand capacity and make use of the waste CO₂. In future, plants could shift to using biomass or direct air capture for a CO₂ source to ensure low carbon production. Over time, the shift away from urea would reduce the requirement for CO₂.

5.2.4.2 Storage and Transportation Implications for Other Fertilizers

In the shift to non-urea fertilizers, it will be important to deploy improved storage and transportation infrastructure for DAP and other CF products. Urea is particularly suited to India, as it is relatively easy to transport and store, without the need for careful handling or temperature-controlled environments. Other fertilizers, particularly ammonium nitrate, require temperature and humidity-controlled environments, which may be difficult to implement rapidly across India.

5.2.4.3 Existing Stock of Natural Gas Plants

There is a large existing stock of natural gas plants, with long lifetimes. Whilst the stock is fairly old, many of these plants will still be able to produce cost-effective fertilizer products for many years to come, thereby slowing the rate of transition from fossil fuel-based production to low carbon production. As a result, many natural gas plants are expected to produce fertilizer products in 2050. It is possible that alternative methods of emissions reduction could be explored for these plants, such as retrofitting CCUS technology or replacing a part of the hydrogen requirement with green hydrogen.

5.2.5 Future Scenarios

Based on this analysis, we assume that green ammonia plants start to be built from 2030, steadily making up more of the share of new capacity additions, until all new capacity additions are from green ammonia plants. By 2050, this results in around a one-third of the ammonia plant capacity being from green sources.

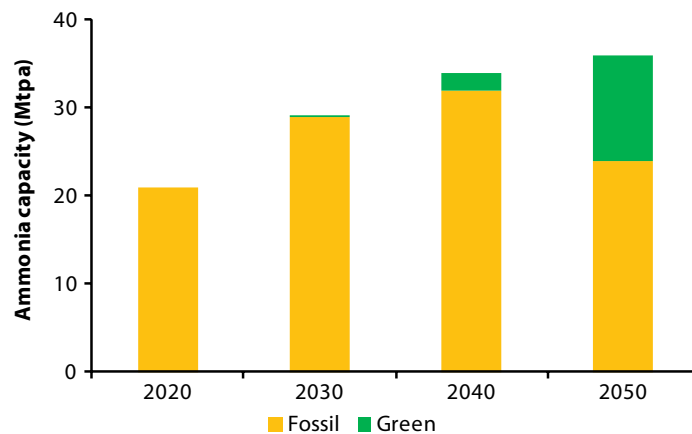


Figure 28: Baseline scenario for green ammonia production capacity, 2020–2050

Source: TERI analysis

Whilst a stark shift from today, this would leave significant emissions from the sector even out to 2060 (Figure 29). To achieve faster rates of deployment of green ammonia production, additional policy support from the government would be required. Under our **Low Carbon** scenario, where green ammonia plants are established from 2025, continuing to displace natural gas plants at a faster rate out to 2050, we could expect green hydrogen requirements to more than double than the **Baseline** scenario.

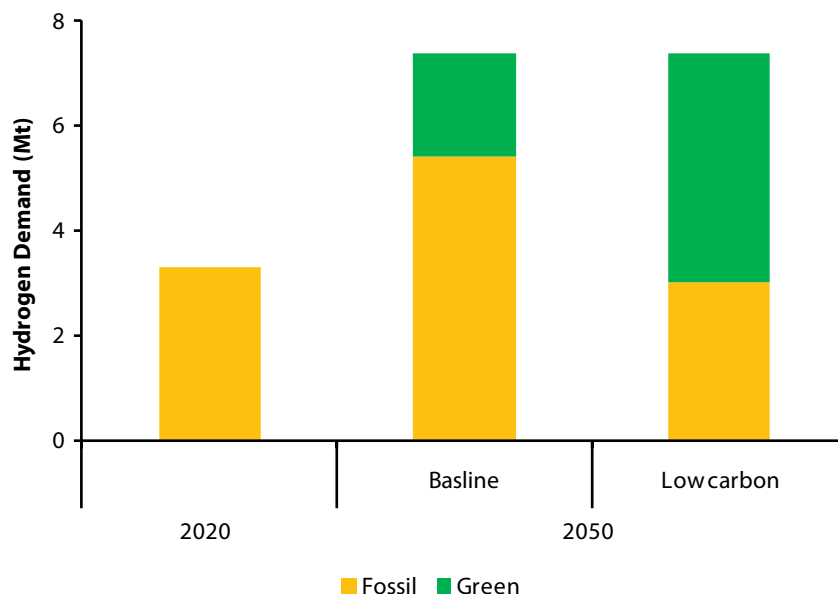


Figure 29: Hydrogen requirements for ammonia under Baseline and Low Carbon scenarios, 2050

Source: TERI analysis

The overall hydrogen demand is projected to increase from just over 3 Mt today to around 7.5 Mt by 2050. We estimate that approximately 2.0 Mt of this could be met through green hydrogen in the baseline, based on expected cost reductions from green hydrogen production. With further policy push, this could increase to 4.5 Mt by 2050.

5.3 Methanol

5.3.1 Background

The methanol industry in India today is relatively small, with a demand of around approximately 2 Mt from other industrial users for the production of chemicals. Nonetheless, demand is expected to grow rapidly with the share of methanol imports remaining fairly high. This is primarily a result of a large portion of methanol production coming from natural gas, which is abundantly available in the Middle East at extremely low prices. China also produces significant quantities of methanol, largely from coal and coke oven gas. The average price of natural gas used in methanol production in the Middle East is approximately \$2–3/mmbtu, versus an imported price of natural gas at around \$10/mmbtu for India. Due to this price differential, large-scale domestic production using natural gas is unviable.

The Government of India has ambitious plans to expand the domestic methanol industry, through the use of coal to methanol technologies (NITI Aayog, 2018). The goal is for methanol to displace oil products in major end-use sectors, such as transport (road, rail, and shipping), industry (distributed generators, boilers, heaters), and residential (heating and cooking). The extent to which methanol will displace oil products in these sectors will

also depend on the growing pace of electrification of these end-uses, which would be more efficient, although there are challenges to achieve rapid deployment at scale.

There are several initiatives supporting the increased supply and use of methanol (NITI Aayog, 2018), including the following:

- **Road transport:** The Ministry of Road, Transport and Highways (MoRTH) is encouraging 20% DME (di-methyl ether or D100) blending with LPG and a notification for M-15, M-85, M-100 blends has been issued for the transport sector. Test Standards / Test Plans for M-15 blend and testing are being evolved in consultation with Indian Oil Corporation Limited (IOCL), Automotive Research Association of India (ARAI), and Society of Indian Automobile Manufacturers (SIAM).
- **Railways:** The Research Designs & Standards Organisation (RDSO) is working towards blending methanol in the range of 5–20% through direct fuel injection in diesel locomotives.
- **Marine:** As part of the inland waterways programme, three boats and seven cargo vessels are being built by Cochin Shipyard Limited to use methanol as a marine fuel.
- **Residential:** On 5 October 2018, Assam Petro-chemicals launched Asia's first methanol cannister cooking fuel program. The pilot has resulted in 20% energy savings in cookstoves when compared to LPG, which further leads to significant savings over biomass cooking.
- **Power:** Thermax Limited and Kirloskar Oil Engines Limited successfully developed a methanol-based reformer using a Direct Methanol Fuel Cell (DMFC) for use in remote mobile towers.

In terms of methanol production, the main routes being explored are through the use of biomass, coal, and electricity. Due to limited supplies of sustainable biomass, the electric and coal routes are likely to provide the bulk of future methanol supply, with coal to methanol receiving most attention to date. As part of the 'methanol economy' program, around 20 Mt of production capacity is being planned, mainly using coal to methanol technology (NITI Aayog, 2018). Whilst there is significant momentum behind in terms of increase in supply and use of methanol in India, its uptake will ultimately be driven by how competitive it is with the alternatives. Across the transport, industry, and power uses, direct electrification will ultimately prove a more cost-effective, lower emission solution. As such, whilst the domestic methanol economy will increase in the decades to come, this will likely fall below the current stated targets.

5.3.2 Demand

We expect demand for methanol to increase rapidly in the coming years, driven by a certain amount of policy support from the Government of India. We expect around a five-fold increase between now and 2050, largely driven by continued use of methanol in the chemical industry. We also expect the import share to reverse from 80% today to 20% by 2050, driven by supportive policy and a stated aim to reduce energy imports (Figure 30).

Nonetheless, we do not foresee the same scale of demand growth as is being anticipated by the government, due to alternative fuels becoming more competitive versus methanol in several sectors where it is being targeted. This includes battery electric vehicles, electric trains, hydrogen trucks, and improved rural power supplies.

The level of methanol production equates to just over 1 Mt of hydrogen demand by 2050, far lower than what we see in the fertilizer sector (Figure 31). This is due to a lower overall demand for methanol versus fertilizers, and a lower hydrogen requirement per tonne of methanol versus ammonia.

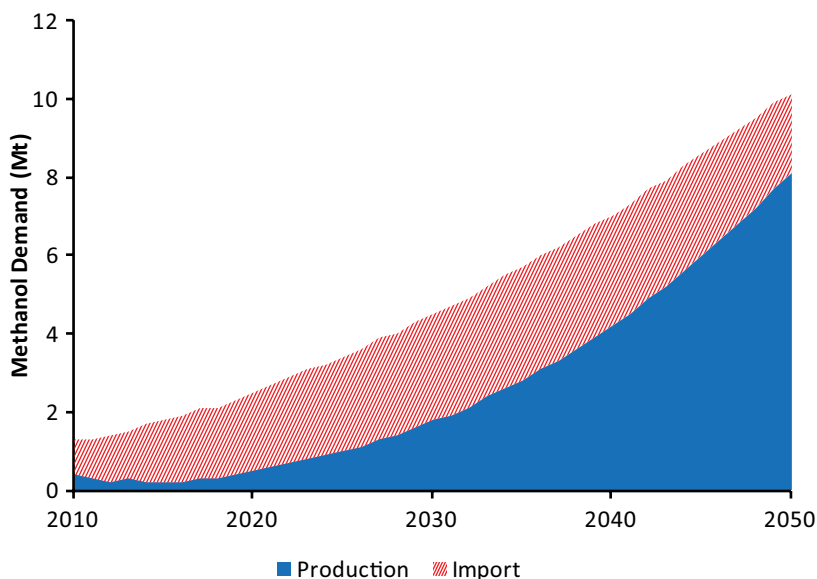


Figure 30: Methanol demand – domestic production and import, 2020–2050

Source: TERI analysis based on (Ministry of Chemicals and Fertilizers, 2019)

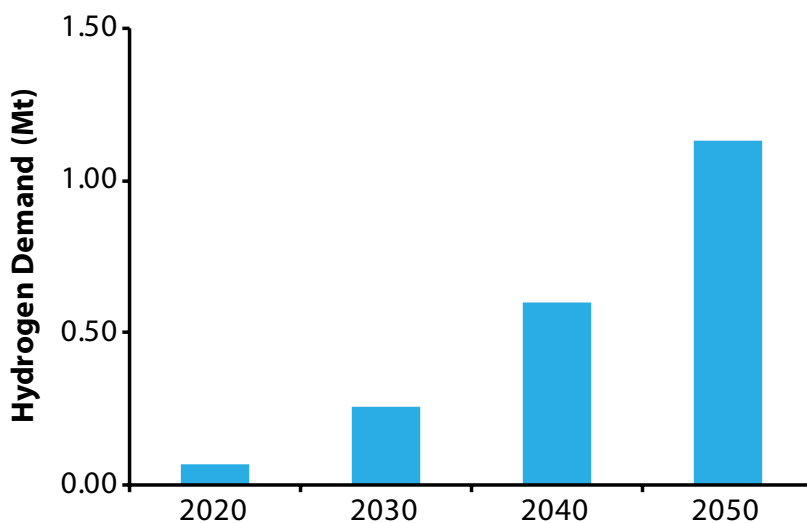


Figure 31: Hydrogen demand for methanol, 2020–2050

Source: TERI analysis

5.3.3 Low carbon Options

The principle way of producing methanol today is by using natural gas. Due to extremely low prices of natural gas in the Middle East, India imports around 80% of its methanol as the final product. If India were to import natural gas at the current price (\$8–12/mmbtu), the cost of methanol would be approximately Rs. 25,000–35,000/t versus an imported price in the range of Rs. 20,000–25,000/t (Figure 32).

At these natural gas prices, we could expect methanol, produced from green hydrogen, to become competitive starting today. A recent round-the-clock power bid announced by SECI in January 2020 had electricity being

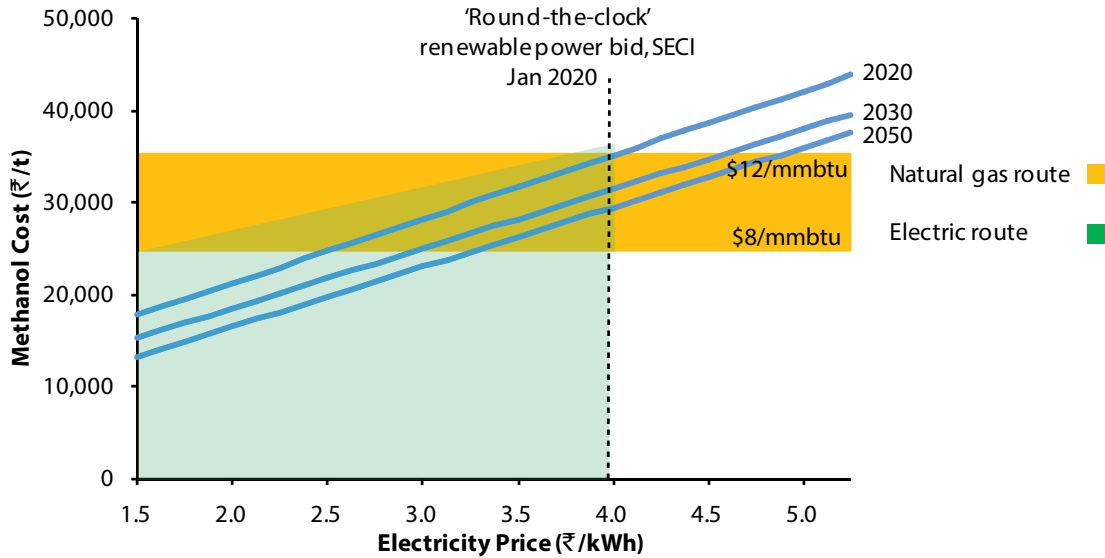


Figure 32: Costs of methanol production – electric vs. gas route

Source: TERI analysis based on (IEA, 2019)

supplied at Rs. 4.0kWh. As costs of renewable electricity continue to fall, methanol from domestically produced green hydrogen could start to displace methanol imports (Figure 33).

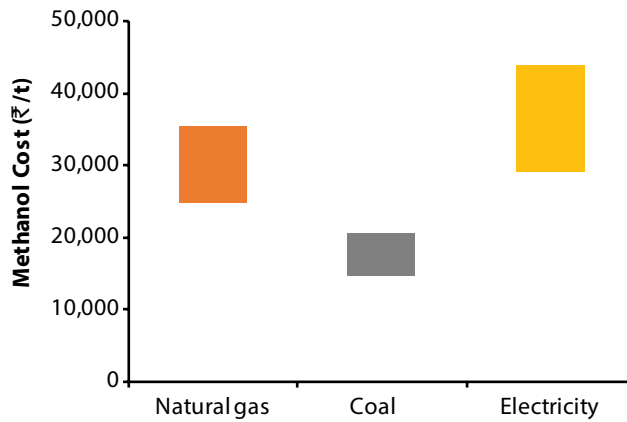


Figure 33: Costs of methanol production from various routes, 2020–2030 costs

Source: TERI analysis based on (IEA, 2019)

However, it is also worth considering the costs of coal to methanol, which has received significant support from the government. Coal to methanol is far more cost-effective than coal to ammonia due to low capital and operational cost of plant, where coal to methanol is around 60% of the cost. This is mainly due to the simpler processes required in coal to methanol, which only requires coal gasification plus conversion to methanol. As such, we expect coal to methanol to continue to compete with both the natural gas and the electric routes over this entire time period, making it challenging to reduce emissions from domestic methanol production, without policy support.

5.3.4 Barriers to a low Carbon Transition

5.3.4.1 Low Cost of Methanol Imports

The Middle East region has some of the lowest costs of natural gas production in the world, allowing highly cost-effective production of key products, such as methanol. The relatively low cost of transporting methanol to India means that this will likely remain a part of India's energy mix for years to come, even as domestic production scales up.

5.3.4.2 Low Cost of Domestic Coal

The recent announcements by the government, aimed at expanding coal to methanol plant capacity, will make it more challenging for green hydrogen to compete in the domestic production of methanol. Out to 2050, it is expected that coal to methanol will be a lower cost route for methanol production versus the electric route. This is primarily driven by the cheap and plentiful domestic coal supplies as well as the cost-effective conversion process. Without additional policy to incentivize an accelerated shift towards green hydrogen for methanol production, coal gasification will continue to be the most cost-effective route. This is different for coal to ammonia, where the extra steps to process the coal gas make it less cost-competitive than coal to methanol.

5.3.4.3 CO₂ Requirements for Methanol

As with urea, an external source of CO₂ would be required to produce methanol, if green hydrogen is being used. In the near- to medium-term, CO₂ could be sourced from nearby industrial units, recycling captured CO₂. However, this does not reduce CO₂ to zero, as it would still be emitted. To reduce emissions from the process to zero would require a CO₂ source from biomass or from direct air capture, which may be restrictive due to availability or cost.

5.3.5 Future Scenarios

In our **Baseline** scenario, coal to methanol would increase out to 2050, in line with the government's plans to expand the use of domestic coal reserves. Being the most cost-effective production route, it will be challenging for green hydrogen to compete without government support (Figure 34).

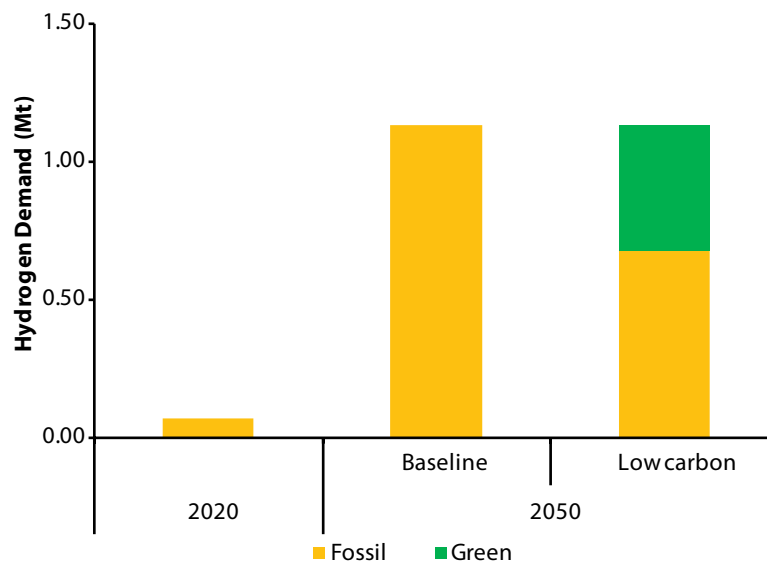


Figure 34: Hydrogen supply for methanol production in the Baseline and Low Carbon scenarios, 2020 and 2050

Source: TERI analysis

In the **Low Carbon** scenario, where the government is targeting a more ambitious emissions reduction target, we could expect to see green hydrogen displacing any natural gas-based production, as well as limiting the amount of coal to methanol plants being built. This would require a significant emissions penalty for green hydrogen to start being competitive with coal-based production in 2030. In such a scenario, green hydrogen demand would be around 0.5 Mt in 2050.

5.4 Refineries

5.4.1 Background

The refinery industry in India currently processes a large amount of crude oil, with final products being mainly used in transport and industry. Crude oil accounts for around 30% of the primary energy demand in the country, with more than 80% of it being imported (IEA, 2020).

Hydrogen is mainly used to process crude oil into refined products and for desulphurisation, with different products allowing different levels of sulphur, based on regulations and industry requirements. The lower the sulphur content requirement, the higher the demand for hydrogen. Policies such as the BSVI Standards, which require lower amounts of sulphur in transportation fuels, are driving increased demand for hydrogen in this sector.

In previous years, naphtha was the main fuel being used to produce hydrogen via on-site catalytic reformation, which supplied the need of hydrotreating and hydrocracking processes. Over time, this was replaced with natural gas reformation due to the increased demand for naphtha to produce petrochemicals at refineries to maximize profit.

In refineries, some hydrogen is already produced as a by-product during the refining process, however, in most cases this by-product hydrogen is insufficient to meet total refinery hydrogen demand. As such additional on-site hydrogen production is often required, using natural gas or naphtha reforming. The natural gas reforming units are typically built on-site to meet the overall demand for hydrogen at the refinery over the course of its lifetime. For example, BPCL's refinery in Kochi is being supplied on a 20-year contract by a reformer of Air Products (PR Newswire, 2013).

India currently has a refining capacity of 254 Mtpa, which is the fourth largest in the world after the United States, China, and Russia. Refinery capacity and complexity have been increasing to cater to the increased demand of petroleum products and to displace imports of refined products, thus ensuring greater value addition within India. By 2030, India targets to double the refining capacity to around 500 Mtpa (Business Standard, 2020).

India's domestic crude oil is predominantly light and sweet¹, with a specific gravity ranging from 32 to 38 API and sulphur content below 0.5%. However, this only makes up around 17% of the total crude oil supply (Petroleum Planning and Analysis Cell, 2020). More than 80% of India's crude oil is imported, primarily from the Middle East, which tends to have a high sulphur content.

During 2019–20, petroleum product consumption in India was around 215 Mt. India currently has a surplus refining capacity due to the promise of strong future growth in the domestic market. Over the last five years, the demand of petroleum products grew at a CAGR of 5–6%, in line with rapid economic growth (Petroleum Planning and Analysis Cell, 2020).

¹ 'Light' meaning easier to distil and 'sweet' having a lower sulphur content.

Refineries are currently undergoing some upgrades in order to meet new fuel specification regulations, through adding hydro-processing capacities, which use hydrogen for removing sulphur from the middle distillates, such as gasoline (ICCT, 2012). Hydrogen is also used in the hydrocracking process to produce valuable products from heavier oil residues. However, it is predominantly the requirement of ultra-low sulphur fuels that is expected to drive the demand of hydrogen in refineries in the future.

5.4.2 Demand

To project demand for the main oil products in India, we first took historical data from the Petroleum Planning and Analysis Cell (PPAC) to understand past trends. We then derived a relationship between GDP and these products, allowing us to project forward in line with assumptions around economic growth. There is, of course, a high degree of uncertainty in such projections. In the **Baseline** scenario, we assume that historical trends continue at a similar rate, seeing large growth across all oil products (Figure 35). We align the road transport fuel projections with the transport scenarios in the previous section to take into account that even in the **Baseline** scenario, we expect a fairly significant shift away from ICE vehicles.

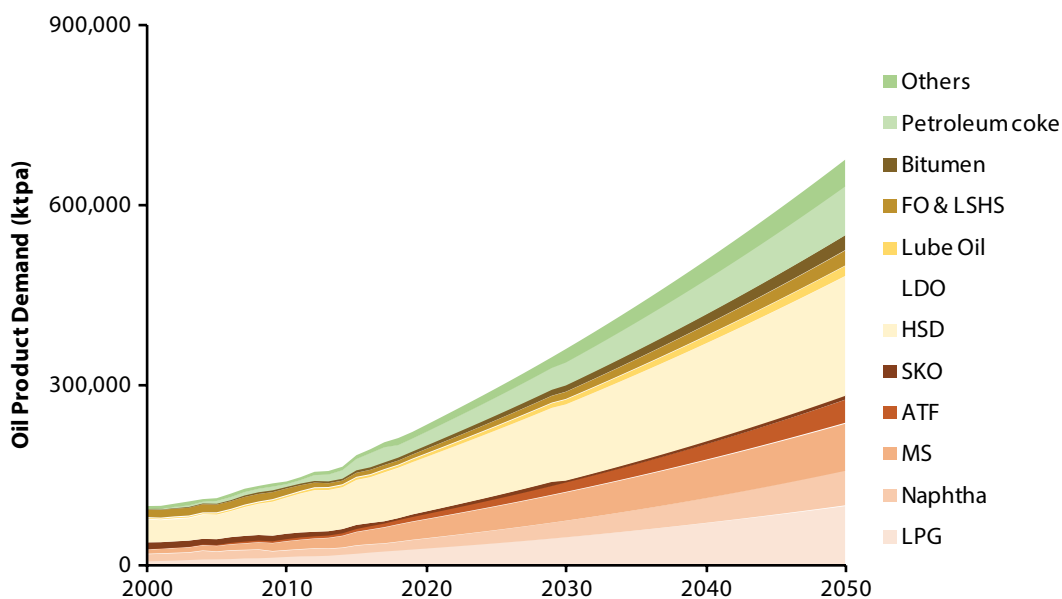


Figure 35: Oil product demand in the Baseline scenario, 2000–2050

Source: TERI analysis based on (Petroleum Planning and Analysis Cell, 2020).

Note: FO & LSHS = Fuel Oil and Low Sulphur Heavy Stock, LDO = Light Diesel Oil, HSD = High Speed Diesel, SKO = Superior Kerosene Oil, ATF = Aviation Turbine Fuel, MS = Motor Spirit, LPG = Liquid Petroleum Gas.

In the **Low Carbon** scenario, demand for oil products reduces significantly over the time period, reaching around 40% lower in 2050 (Figure 36). This is driven by a faster roll-out of BEVs and FCEVs versus the **Baseline**, which reduces the consumption of HSD and MS, in particular. For other oil products, such as fuel oil and petroleum coke, we also expect a rapid reduction in demand, driven by more aggressive policies penalising emissions and promoting electrification. Despite these impacts, we can still observe a twofold increase in production between 2020 and 2050, highlighting the challenge of rapid transition away from oil in a country with such rapidly growing energy demands.

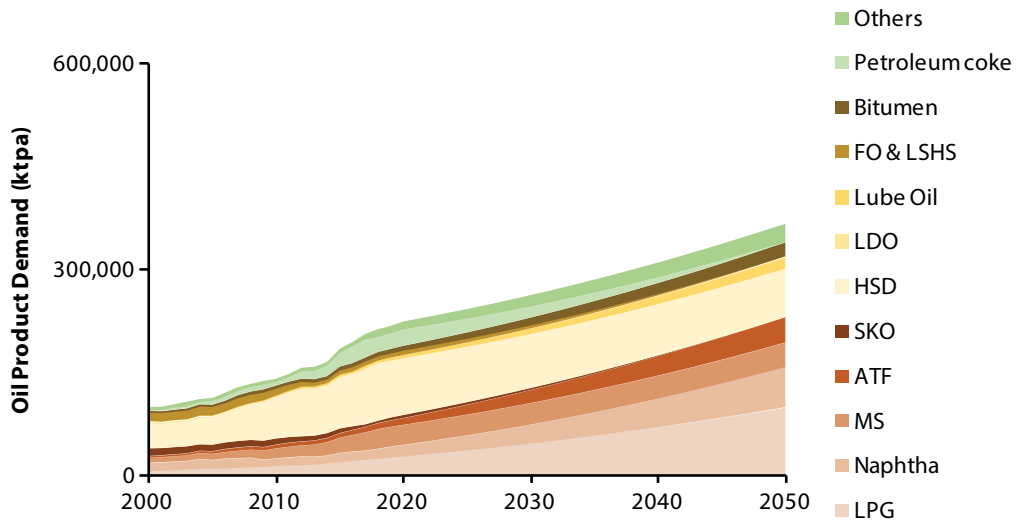


Figure 36: Oil product demand in the Low Carbon scenario, 2000–2050

Source: TERI analysis based on (Petroleum Planning and Analysis Cell, 2020).

Note: FO & LSHS = Fuel Oil and Low Sulphur Heavy Stock, LDO = Light Diesel Oil, HSD = High Speed Diesel, SKO = Superior Kerosene Oil, ATF = Aviation Turbine Fuel, MS = Motor Spirit, LPG = Liquid Petroleum Gas.

Estimating future production under such a scenario allows us to calculate the amount of hydrogen required in the sector within India. Using historical import and export trends based on PPAC data, as well as the oil product demand projections, we produce production scenarios out to 2050. Similarly, for the **Low Carbon** scenario, we expect oil product production to increase by a factor of 1.6 between 2020 and 2050 (Figure 37). This represents significant additional refinery capacity even in a world where the transition to low carbon transport is accelerated.

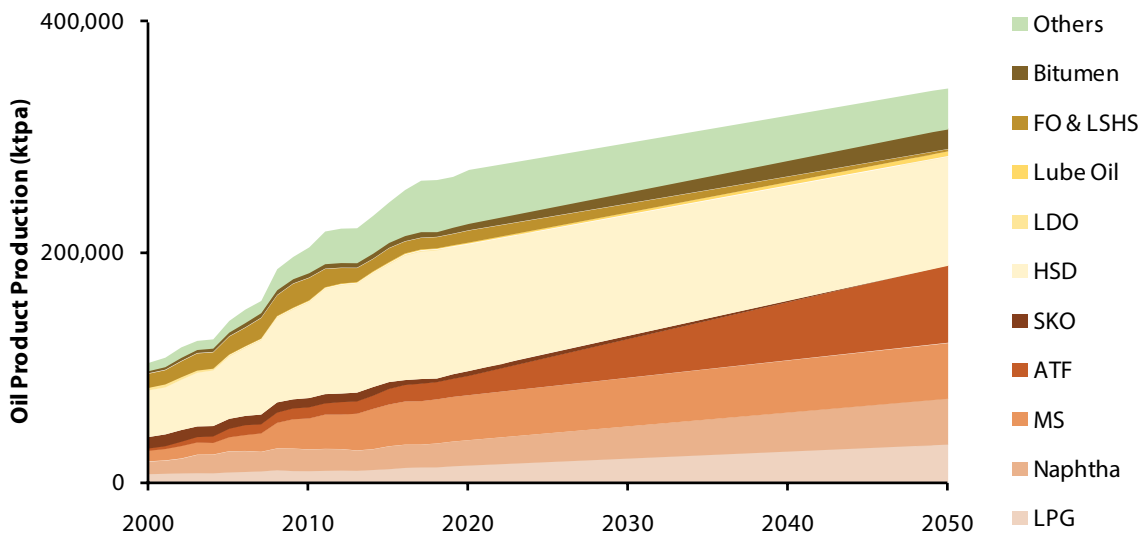


Figure 37: Oil product production in the Low Carbon scenario, 2000–2050

Source: TERI analysis based on (Petroleum Planning and Analysis Cell, 2020)

From these production figures, we now estimate the hydrogen required to process these fuels. The principal use of hydrogen in refineries is to remove sulphur from various products; with fuels such as high speed diesel (HSD) facing strict regulations, such as Bharat Standard VI (BSVI) standards, which limit the amount of sulphur. To estimate the total amount of hydrogen required, we take the following steps:

- Estimate the allowed sulphur content in the different refinery products
- Estimate the levels of sulphur inherent in the crude oil feedstock
- Subtract the allowed sulphur from the inherent sulphur to establish how much sulphur needs to be removed from the total of refinery products
- Estimate the amount of hydrogen required to remove this amount of sulphur
- Estimate the amount of by-product hydrogen from CNR facilities
- Subtract by-product hydrogen from overall hydrogen demand
- The result of these steps equals out estimation of final hydrogen demand.

Table 15 shows the allowed sulphur content of the main oil products, indicating that the tightest restrictions are on road transport fuels, such as diesel. Using this information, we can estimate the total allowed sulphur content across the various products, at the production levels shown in Table 15. We can see from Figure 38 that the allowed sulphur content is around 600t in 2020, rising significantly in the **Baseline** scenario, with growing demand for high sulphur products, such as fuel oil. Allowed sulphur in the **Low Carbon** scenario does not differ greatly from today as a result of demands for most high sulphur products showing either limited growth or a decline.

Table 15: Allowed sulphur content for various oil products

Product	Allowed sulphur content (g/t)
LPG	150
Naphtha	50
Gasoline	50
Kerosene	1,000
Diesel	10
Fuel oil	5,000
Other products	10,000

Source: (MRPL, 2019)

To estimate how much sulphur needs to be removed from the oil, we need to understand the amount of sulphur inherent within the crude oil feedstock. The Indian basket is a combination of imported benchmark crude oils, such as Brent (coming from Northwest Europe), Dubai, and Oman. The current basket is approximately a ratio of 25:75 from Europe and the Middle East, respectively. This results in an average sulphur content of 1.275% for Indian refiners. This, combined with domestic oil production (~17% of total crude processed), which has a lower sulphur content (less than 0.5%), yields an overall average sulphur content of 1.15% (ICCT, 2020).

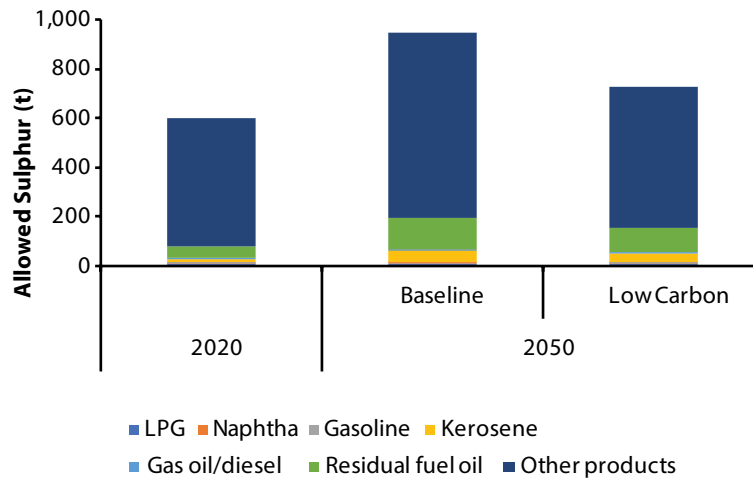


Figure 38: Allowed sulphur in oil products, 2020 and 2050

Source: TERI analysis based on interactions with the IEA

After estimating the sulphur in the crude oil feedstock, we subtract the allowed sulphur content to provide us with an estimate of how much sulphur needs to be removed from these products. For example, in 2020, the total amount of sulphur inherent in the feedstock is approximately 3,500 ktpa. The allowed sulphur is around 590 ktpa, indicating that around 2,910 ktpa needs to be removed through the use of hydrogen in the desulphurisation process. For each tonne of sulphur, 870 kg of hydrogen is required to remove it from the product. Using these calculations, we can produce a final hydrogen demand estimation for the refinery sector (Figure 39).

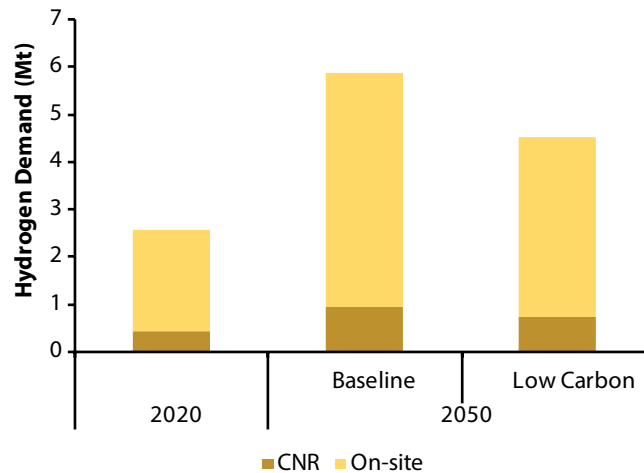


Figure 39: Hydrogen demand in refineries, 2020 and 2050

Source: TERI analysis based on interactions with the IEA

In 2020, total refinery demand for hydrogen is 2.6 Mt, or around 40% of total hydrogen demand in India. In the **Baseline** scenario, this would increase to nearly 6 Mt, as demands for low sulphur fuels, such as diesel and motor spirit (petrol), continue to grow significantly. In the **Low Carbon** scenario, total hydrogen demand is around 5 Mt, reflecting the lower demands for low sulphur fuels with a growing shift to BEVs and FCEVs.

It is also important to note that a portion of hydrogen demand is met via by-product hydrogen from catalytic naphtha reformer (CNR) units. These will continue to supply low-cost hydrogen into the future and so are unlikely to switch to low carbon alternatives. We estimate that CNR units supply around 15% of the hydrogen required in India’s refineries.

5.4.3 Low Carbon Options

To reduce emissions from hydrogen production for refineries, we assume that the current on-site, dedicated hydrogen production could be replaced by green hydrogen, being the most cost-effective low carbon route for India in the coming years. From our analysis of various production methods in Section 3.1, we show that costs of hydrogen from renewables and electrolysis could start to compete with the costs of hydrogen from SMR around 2030.

5.4.4 Barriers to a Low Carbon Transition

5.4.4.1 Supply of Cost-effective Low Carbon Heat

The refining process also requires some heat, which is largely supplied by fuel oil, natural gas, or petroleum coke today (TERI, 2015). Moving to a low carbon refinery would require this heat demand to also be met with low carbon sources. The main issue with this is that hydrogen is unlikely to compete with fossil fuels as a means of heat delivery (see Section 5.7). Whilst it is able to compete as a chemical feedstock, as a result of the additional costs of processing fossil fuels, it will be more challenging to compete with directly combusted fossil fuels. Further work is required to understand the extent to which these heat demands could be electrified.

5.4.5 Future Scenarios

Based on this analysis, we have assumed a certain rate of growth in green hydrogen production in the refinery sector. For the **Baseline** scenario, we assume that green hydrogen starts to slowly displace natural gas-based hydrogen from 2030, reaching around a 30% share by 2050. For the **Low Carbon** scenario, we assume that the uptake of green hydrogen in the refinery sector starts slightly earlier, in 2025. This is driven by faster cost reductions and greater levels of policy support, such as an emissions penalty or green subsidy. With these measures, green hydrogen could supply around 50% of the refinery industry’s requirements in 2050 (Figure 40).

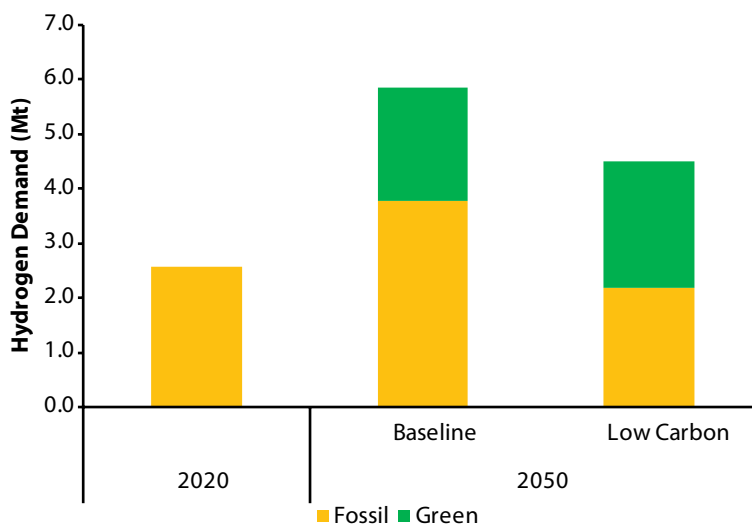


Figure 40: Hydrogen demand and supply for refineries in the Baseline and Low Carbon scenarios, 2020 and 2050

Source: TERI analysis

5.5 Iron and Steel

5.5.1 Background

India is currently the world's second largest steel producer, and third largest steel consumer. The steel industry in India is far more heterogeneous than in many other countries, with a wide range of different-sized facilities in the primary and secondary steelmaking sectors. There are also a number of different technologies currently being used, including the Blast Furnace – Basic Oxygen Furnace (BF-BOF), coal-based Direct Reduction (DR), gas-based DR, Electric Induction Furnace (EIF) and Electric Arc Furnace (EAF). Coal-based DR in particular is unique to the Indian steel sector, which can meet local steel demands at costs that are competitive to larger integrated steel plants. Reliance on this technology is driven by India's cheap domestic coal reserves, and the lack of sufficient domestic natural gas supplies and coking coal of sufficient quality.

As demand for steel slows in developed regions of the world, most new steel demand will come from large industrialising countries in South Asia and Africa. India in particular will contribute significantly to this steel demand growth, requiring new primary steelmaking capacity, alongside ambitious scrap steel policies, which can support growth in secondary steelmaking. Low-emission primary steelmaking technologies will be required to ensure the steel sector can reduce emissions to near zero levels by the mid-century or 2060.

5.5.2 Demand

We expect steel demand to increase rapidly out to 2050, satisfying growing requirements of infrastructure development in India. We have collected historical data from the World Steel Association to understand historical trends of steel demand for India. Projecting forward, we use a multivariate econometric model (Hall, Spencer, & Kumar, 2020).

The **Low Carbon** scenario is combined with resource efficiency measures, which result in a more efficient use of steel across the economy versus the international and historical experience. This sees steel demand around 25% lower in 2050 than the **Baseline** scenario. By 2050, we expect steel demand to be around 350 Mt in such a scenario. New low carbon capacity will be required to meet this growth sustainably (Figure 41).

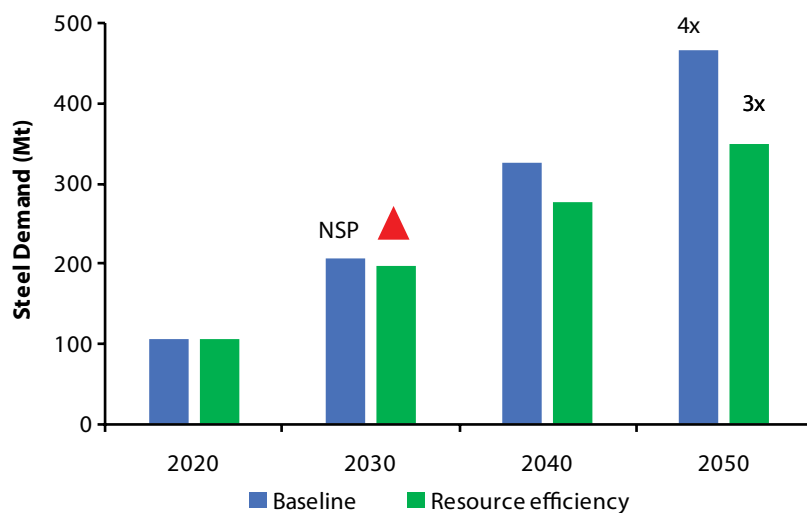


Figure 41: Demand for steel under a Baseline and Resource efficiency scenario, 2020-2050

Source: TERI analysis based on (Ministry of Steel, 2017); (Hall, Spencer, & Kumar, 2020).

Note: NSP = National Steel Policy projection.

5.5.3 Low Carbon Options

There has been increasing activity around emerging low-emission steelmaking technologies, driven in part by generous R&D support, alongside increasingly stringent emissions reduction policies, particularly within the European Union. The result of these policies has been the development of a few leading technology routes, which have the potential to achieve emissions reduction at the scale required.

Based on our assessment of potential technologies, the two leading routes which have the greatest potential for India are smelting reduction with CCUS – although CO₂ storage is a significant uncertainty (see Box 4) – and hydrogen direct reduction. Table 16 describes the main aspects of these two technologies.

Table 16: Hydrogen direct reduction and smelting reduction with CCUS

Hydrogen direct reduction	Smelting reduction with CCUS
<ul style="list-style-type: none"> Builds on well-understood gas-based direct reduction technology. Plants have been operating on very high shares of H₂ (+70%) for decades, in e.g. Trinidad & Tobago, Mexico, USA. The leading demonstration project is the HYBRIT facility in Sweden. The main barrier is costs of low carbon hydrogen and access to renewable electricity. 	<ul style="list-style-type: none"> Smelting reduction technologies have been used for many years, e.g. Finex, Corex. Removes the need for sintering and coke plant, thus reducing capex and opex by a significant margin. The leading technology paired with CCS is Hlsarna trial facility in Europe. The main barrier is the availability of CCUS infrastructure, which can add significant costs.

Source: (Hall, Spencer, & Kumar, 2020; Midrex, 2018; IEA, 2019; Tata Steel, 2020)

An important consideration for low carbon steelmaking routes in India is the lifetime of the plants and the possibility of retrofit in the coming decades. Steel plants have long lifetimes (30 years plus), resulting in significant potential emissions lock-in for fossil fuel plants being built in the coming years, when low carbon options might not be available.

Figure 42 illustrates two potential transition pathways for the leading technologies discussed earlier. For the hydrogen route, gas-based capacity could be built in the 2020s, using natural gas or coal-based syngas, which is more readily available. This could then be switched to low carbon hydrogen over time, reducing emissions without a significant change in the infrastructure. Alternatively, steel producers could establish smelting reduction facilities, such as Hlsarna, over the coming decades, which could then be retrofit with CCUS technology to reduce emissions. Brownfield sites are more challenging. As existing fossil fuel infrastructure is likely to remain competitive over its lifetime, it is unlikely that plants will be closed prior to the end of their economic lifetime.

To understand the cost-competitiveness of using smelting reduction with CCUS versus hydrogen direct reduction (plus electric furnace) to produce low emissions steel, we can compare these technologies with the cost of steel production from existing routes. Data was gathered from the available literature and industry experts to develop cost assumptions for the Indian context. Costs of capital are varied on a consistent basis between routes ranging from 10% to 12% (NITI Aayog, 2016).

We can see from Figure 43 that costs of steel production from the main conventional routes in India range from around \$300/t of crude steel, to just below \$500/t. The cheapest route in this analysis is the coal-based direct reduction using a rotary kiln. Lower capital and operational costs, as well as having access to cheaper, domestically available fuel mean that this route is one of the cheaper ways to produce steel in India today. However, many of these plants are highly polluting and the quality of steel produced is not always sufficient for certain specialist applications.

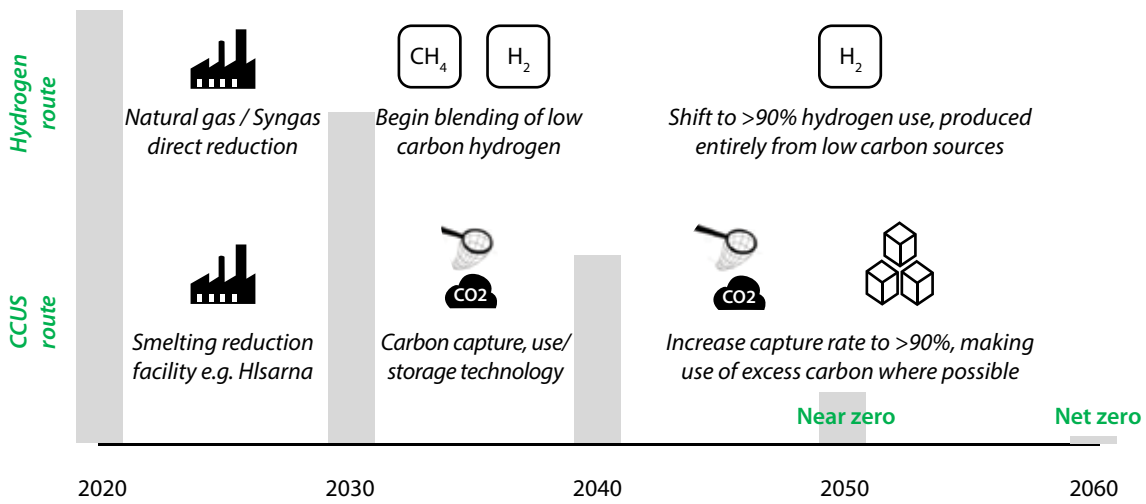


Figure 42: Pathways for decarbonizing primary steel production in India, 2020-2060

Source: TERI analysis

Next most competitive is the blast furnace with basic oxygen furnace (BF-BOF), which is the dominant route in India. Costs of steel production vary based on the costs of coking coal, which can fluctuate significantly over time (CRISIL, 2018). Natural gas direct reduction is costlier in India due to the higher costs of natural gas, as well as uncertainty around its continuous availability. The range illustrated assumes delivered costs of \$8/mmbtu to \$12/mmbtu, which represents the historical range of imported natural gas prices.

The costs of smelting reduction with CCUS assume that both capital and fixed operating costs are reduced versus the BF-BOF plant due to the removal of coke ovens, sintering plants and pellet factories. Moreover, using thermal coal over coking coal reduces the fuel costs. Without CCUS costs, the costs of steel production from a smelting reduction plant would be around 20% cheaper than the conventional BF-BOF route (Figure 43). However, with the addition of CCUS infrastructure at cost of around \$20/tCO₂ (IEA, 2020) (a range of \$20-\$80 is shown to reflect uncertainty), costs would be near equivalent to existing BF-BOF. There are also considerable uncertainties with regard to the availability of suitable sites for CCUS near the steel plant locations as well as the costs of CCUS infrastructure in India, which are reflected in the larger cost range for the SR-BOF CCUS route (see Box 4).

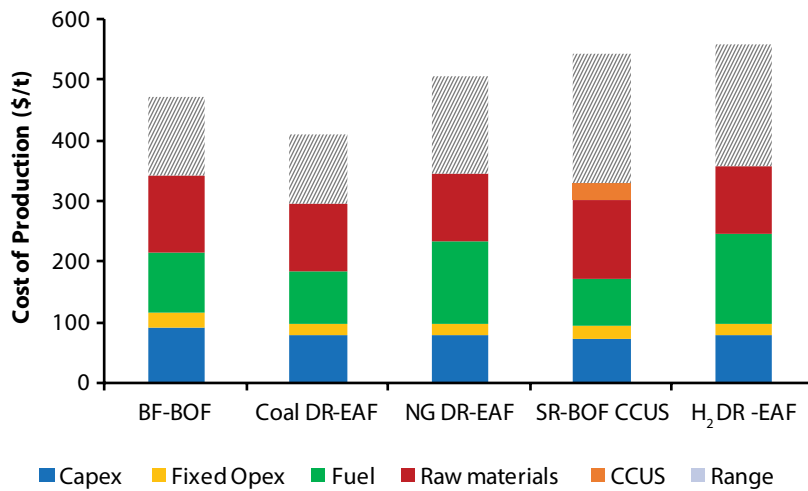


Figure 43: Costs of production from various routes, 2020

Source: TERI analysis based on (IEA, 2019; Hall, Spencer, & Kumar, 2020).

Note: Range reflects changes in the costs of fuel and raw material inputs.

Costs of production from the hydrogen direct reduction route are largely similar to those in the natural gas direct reduction route, with the main difference being the cost of hydrogen as a fuel versus natural gas. In our cost analysis, we assume that hydrogen is purchased from a separate producer by the steel plant, as opposed to having the capital costs of the electrolyzers included in the capital costs of the steel plant. Today, costs of electrolytic hydrogen can be as high as \$8/kg, factoring in costs of transportation and storage infrastructure. Assuming the hydrogen is produced on-site, we provide a range of costs between \$2/kg and \$4/kg.

Based on these ranges, it would appear that the smelting reduction route with CCUS would be cheaper than the hydrogen direct reduction route (provided there are suitable sites closer to the steel plant locations). One key sensitivity to explore in a little more detail is how the cost of hydrogen would impact their relative competitiveness and how falling costs of green hydrogen could change this over time.

In Figure 44, we present the range of costs for a smelting reduction plant with CCUS, as well as declining costs of steel produced via the hydrogen direct reduction route, based on declining costs of hydrogen. With costs in excess of \$4/kg today, we can see that hydrogen direct reduction is consistently more expensive than the smelting reduction route. However, as costs of green hydrogen start to fall over time, potentially reaching \$2/kg in 2030 and \$1/kg in 2050 in the most suitable geographies, hydrogen direct reduction could start to compete.

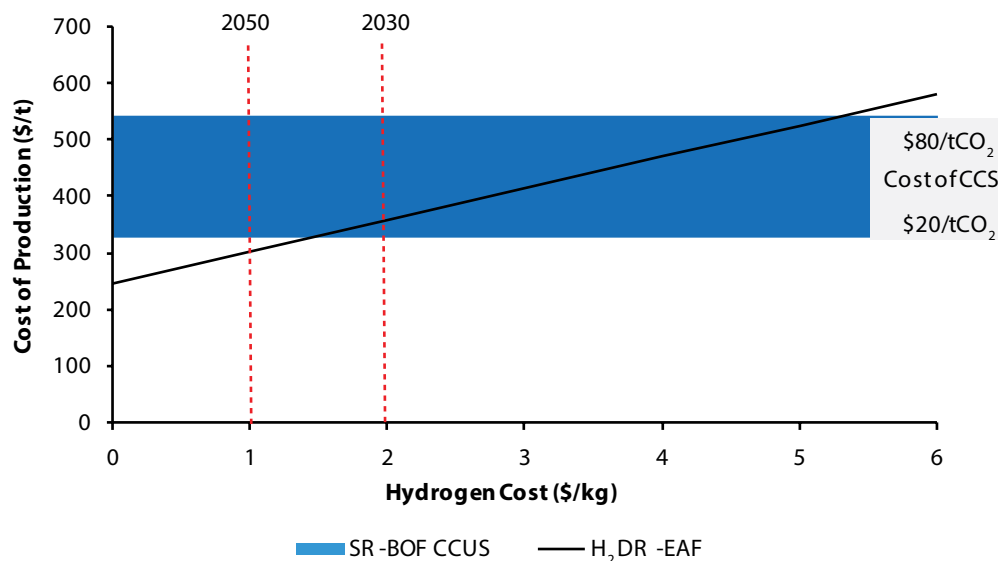


Figure 44: Costs of steel production - H₂-DR vs SR-BOF with CCUS routes

Source: TERI analysis based on (IEA, 2019; Hall, Spencer, & Kumar, 2020; BNEF, 2020)

Note: tCO₂ refers to the cost of carbon capture and storage, not to carbon price.

5.5.4 Barriers to a Low Carbon Transition

5.5.4.1 Low-cost Coal

Nonetheless, without significant policy support in the near-term, hydrogen direct reduction is unlikely to be competitive with smelting reduction with CCUS, or the other incumbent fossil fuel technologies. The major benefit of the smelting reduction technology for the Indian context, based on this analysis, is reduced capital and operating costs versus the conventional routes, as well as a shift away from imported energy sources, such as coking coal.

5.5.4.2 Availability of Low Carbon Electricity

As with all green hydrogen production, large quantities of low carbon electricity will be required. The steel sector is the highest energy-consuming industrial sub-sector, which is a reflection of the energy-intensive processes required to reduce iron ore and make steel. Given this high energy intensity, procuring sufficient low carbon electricity from nearby could be a challenge. From our cost analysis, we have identified local, standalone renewables as the most cost-effective option, although this could be limited in industrial areas where many plants are located near one another.

5.5.5 Future Scenarios

Based on the previous analysis, we assume that hydrogen direct reduction plays a marginal role in the **Baseline** scenario, where there is limited policy support. As costs of green hydrogen fall, we expect hydrogen direct reduction plants to start being built from around 2040, with a relatively slow rate of build out. The costs of coal are sufficiently low that both smelting reduction and coal-based direct reduction facilities would remain competitive, limiting the scale of hydrogen use (Figure 45).

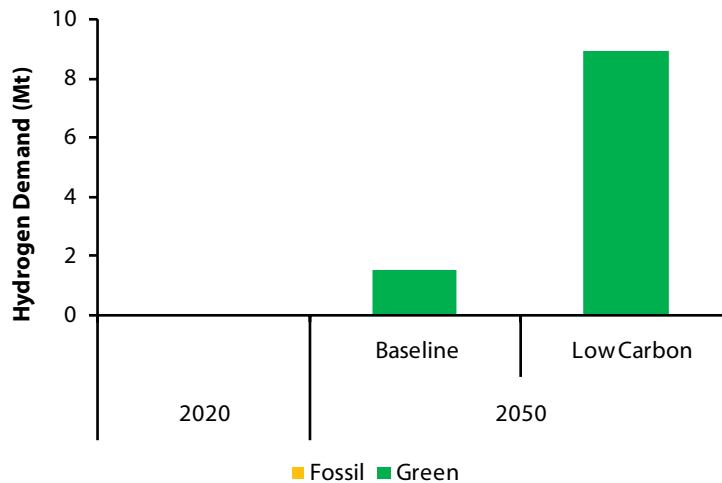


Figure 45: Hydrogen demand for the steel sector in the Baseline and Low Carbon scenarios

Source: TERI analysis

Under the **Low Carbon** scenario, where supportive policies are brought in to accelerate the uptake of hydrogen direct reduction facilities, we see growth in green hydrogen demand from 2030. This increases rapidly out to 2050, making up nearly all new primary capacity additions between 2030 and 2050. This results in around 50% of primary capacity using hydrogen direct reduction by 2050, requiring around 9 Mt of green hydrogen each year. This represents the single largest sector for hydrogen demand by 2050, highlighting both the energy-intensive nature of steel production, as well as the potential contribution hydrogen could play towards reducing emissions in this sector, with the right policy support.

5.6 Caustic Soda

India has a well-established chlor-alkali industry, which produces vital products for the chemical sector. This includes soda ash, caustic soda, and liquid chlorine. India's chlor-alkali industry makes up around 4% of global production capacity, which produces approximately 0.12 Mt hydrogen as a by-product, each year (Bureau of

Energy Efficiency, 2018). This industry is important for the future of hydrogen in India, as the production process outputs hydrogen as a by-product. For one tonne of caustic soda, around 40 kg of hydrogen is produced. This hydrogen is produced via water electrolysis, using brine as the feedstock.

Whilst most of the by-product hydrogen is currently being used in-house or in nearby industries, it may be possible to use some of this hydrogen to kickstart nascent industrial clusters (see section 7.1). In some cases, the hydrogen is currently being used in applications, such as boilers or heating, which could be better suited to direct electrification. Making hydrogen available from these processes to supply other applications, such as transport, would provide additional revenues to chlor-alkali plants, and give impetus to the first step for decarbonizing certain industrial clusters.

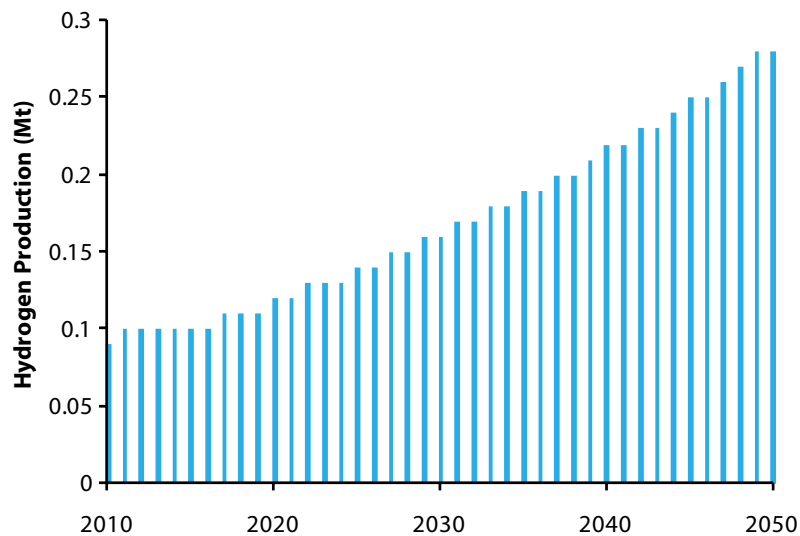


Figure 46: By-product hydrogen supply from caustic soda production

Source: TERI analysis

The caustic soda industry also provides the basis for expanding a nascent electrolyser manufacturing industry in India. The main suppliers of electrolysers technology for the chlor-alkali industry are Asahi Kasai Chemical, Thyssenkrupp, and Chlorine Engineers.

5.7 Industrial Heat

The previous examples of using hydrogen in industry have focused on where low carbon hydrogen has the potential to be used as a chemical feedstock. If hydrogen is to compete elsewhere in industry, it will need to start displacing fossil fuels providing heat for various processes. This includes the production of steam, use in boilers, low-temperature drying, furnaces, and other such applications, which are found commonly across a range of industrial sectors.

Today in India, most industrial heat is provided by low-cost, locally available fossil fuels, predominantly coal. Domestic coal is approximately half the price of imported coal per tonne and provides a very cost-effective means of delivering heat at a large scale. Sectors such as iron and steel, cement, and brick manufacturing consume large amounts of domestic coal. However, distance from domestic coal mines also plays a significant role in the delivered cost, meaning that some facilities near the coast, particularly in the eastern region, choose to import coal instead of using domestic reserves. As such, we represent both assumptions in Table 17 and Figure 47.

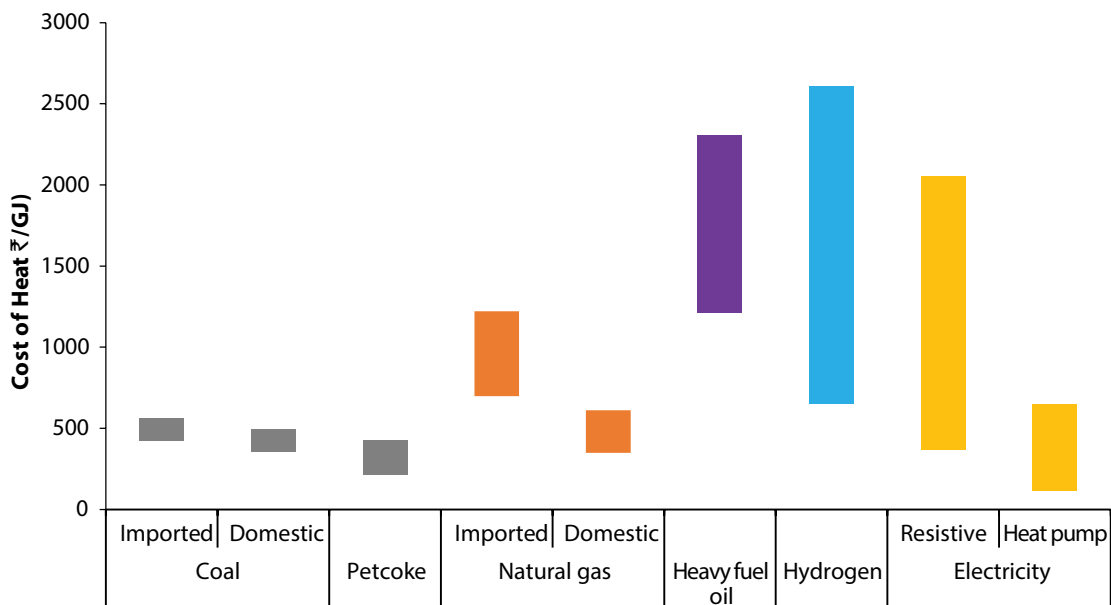
Table 17: Assumptions for various heating fuels

	Fuel	Unit	Energy content (GJ/unit)	Fuel cost (Rs/unit)		Efficiency (%)	Useful heat cost (Rs/G)	
				Low	High		Low	High
Coal	Imported	tonne	26.2	6,660	8,880	60	424	566
	Domestic	tonne	17.4	3,700	5,180	60	355	497
Petcoke		tonne	34.8	4,440	8,880	60	213	425
Natural gas	Imported	mmbtu	1.06	592	1,036	80	698	1,222
	Domestic	mmbtu	1.06	296	518	80	349	611
Heavy fuel oil		tonne	42.8	31,080	59,200	60	1,210	2,305
Hydrogen		kg	0.14	74	296	80	651	2,606
Electricity	Resistive	MWh	3.6	1258	7030	95	368	2056
	Heat pump	MWh	3.6	1258	7030	300	116	651

Source: TERI analysis based on (BNEF, 2020)

Note: Imported coal assumes high grade from Indonesia, equivalent to Indian G4. Domestic coal assumes Indian G11. Domestic natural gas equivalent to \$3-6/mmbtu, imported equivalent to \$8-\$14/mmbtu. The delivered cost varies depending on the distance from source and local/state taxes. Efficiencies are averages. Heat pump efficiency equates to a coefficient of performance of 3.

Petcoke is also a very cost-effective fuel for heating, although its availability is more limited versus domestic coal. However, it is also highly polluting, and work is underway to phase this out as soon as possible. Natural gas is only used for heating purposes if the end-use sector has been prioritized by the government. The largest growth area for natural gas is in the City Gas Distribution (CGD) networks, which are set to expand significantly in the coming decades.

**Figure 47: Cost of heat from various fuels**

Source: TERI analysis adapted from (BNEF, 2020)

The most efficient way to reduce emissions from industrial heat processes is through direct electrification, using renewable electricity. This is already possible in several processes, including forging, foundry, and drying in the food processing industry. If the heat requirements are relatively low (<60°C), then heat pumps can be used at even greater efficiencies, at around 300%. Companies are working on higher temperature heat pumps, which would allow direct electrification of a greater number of processes.

Electric heating can be used at high temperatures in instances where the process materials are electrically conductive, such as the use of electric arc furnaces in steelmaking, which often exceed 1,000°C. For non-conductive materials, such as the manufacture of cement, direct electrification may be more challenging. There is a potential for hydrogen to play a role in this scenario.

Nonetheless, hydrogen will have to compete with direct electrification to be a viable alternative in providing industrial heat. Due to the lack of low-cost natural gas in India, the possibility of using blue hydrogen that would out-compete direct electrification is unlikely. In other regions, where natural gas prices are lower and electricity prices are higher (see Figure 12), using blue hydrogen in industrial heat processes could be viable. In India, it is of greater importance to develop direct electrification technologies, where possible, making use of the low-cost, plentiful renewable electricity. Further analysis will be needed to identify applications where hydrogen could play a role in industrial heat processes.

5.8 Conclusion

It is clear that there is significant potential for hydrogen to continue to play a role in India's industrial sectors. Switching existing emissions-intensive hydrogen production to low carbon alternatives should be a priority, where it is cost-effective. Also, expanding into new sectors, such as steel, offers a significant opportunity for growth. Figure 48 shows that it would be the steel sector that drives new growth, making up over a third of hydrogen demand in the **Low Carbon** scenario.

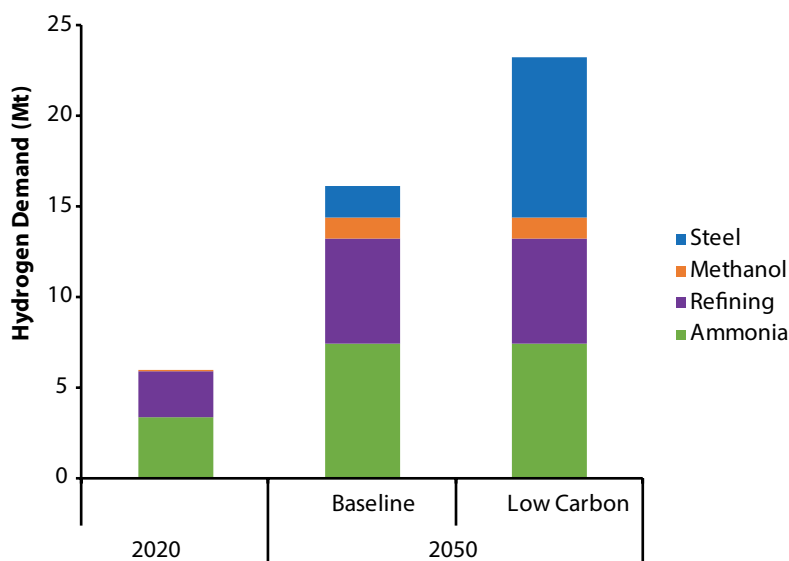


Figure 48: Hydrogen demand for industry in the Baseline and Low Carbon scenarios, 2020 and 2050

Source: TERI analysis

Our **Baseline** scenario shows that, even based on current trends, demand for hydrogen has the potential to increase significantly out to 2050. The most significant uptake is likely to be from the ammonia and refinery sectors, which are already the two largest hydrogen-consuming sub-sectors today. Demand for low carbon hydrogen in the methanol segment will be very low in our **Baseline** scenario, due to the expected low cost of coal to methanol technologies, as previously discussed. Demand for low carbon hydrogen in the steel sector will take off in the later part of the time period, as costs of hydrogen start to undercut the costs of imported coking coal (Figure 49).

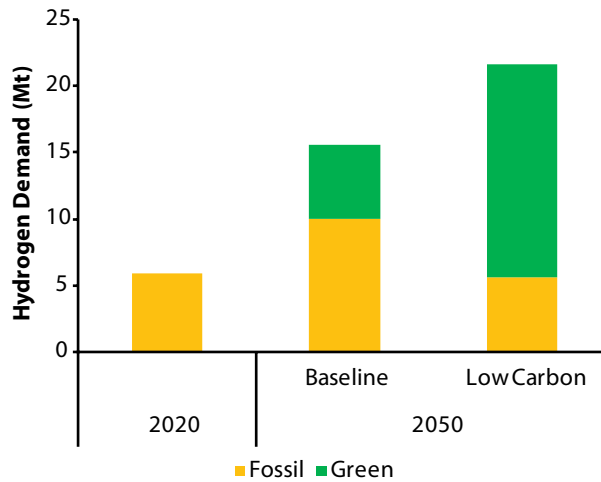


Figure 49: Hydrogen supply in the Baseline and Low Carbon scenarios

Source: TERI analysis

In the **Low Carbon** scenario, the potential demand for green hydrogen is three times what we project in the **Baseline** scenario, reflecting stronger policy support and faster cost reductions in key technologies. In this scenario, we assume that this hydrogen is produced via electrolysis, which appears to be most cost-effective for these industrial uses. To produce 16 Mt of green hydrogen, over 700 TWh of additional electricity would be required, which could be a significant challenge for industrial users looking to situate renewable plants nearby. The scale of this challenge will be discussed in more detail in the next section.

6

POWER



Key messages

- Total electricity demand in India will continue to grow rapidly in the coming years, reaching approximately 5,300 TWh in 2050 in our Baseline scenario.
- In the Low Carbon scenario, additional electricity required for green hydrogen production is around 1,000 TWh.
- Green hydrogen demand, as well as additional electricity demands from faster electrification of transport, partly off-set by greater efficiency, results in total electricity demand of 6,200 TWh in the Low Carbon scenario.
- If met entirely by renewables, this level of electricity demand will start running into land constraints, depending on what we assume is available.

6.1 Introduction

This section analyses the role of hydrogen in the power sector from multiple perspectives. On the one hand, hydrogen production from electrolysis could require substantial amounts of low carbon electricity and may become a significant source of electricity demand growth. On the other hand, as variable renewables increase their share in total Indian electricity generation, the need for electricity storage will increase. Hydrogen may offer a cost-effective form of long-term energy storage that could balance variable renewables across months or even seasons of the year.

6.2 Electricity Scenarios

6.2.1. Aggregate Electricity Demand

As part of this report, we have modelled annual electricity demand out to 2050 in two scenarios, a **Baseline** scenario and a **Low Carbon** scenario. In both scenarios, the underlying economic scenario is the same, and is based on (OECD, 2020). In the **Baseline** scenario, demand is driven by increasing incomes and economic activity, moderated by existing trends in energy efficiency improvements. On the one hand, new end-uses such as EVs or electrolytic hydrogen production grow more modestly than in the **Low Carbon** scenario, driven by weaker policy support to overcome barriers such as infrastructure development, investment risk or cost. On the other hand, energy efficiency is assumed to be pursued much more aggressively in the **Low Carbon** scenario, moderating the growth of electricity demand. At the same time, electrification is extended much further in the **Low Carbon** scenario than in the **Baseline** scenario, and the demand for electrolytic hydrogen is higher.

Within this scenario framework, energy and material demand were derived from a bottom-up, end-use analysis, whereby stocks of energy-consuming equipment or flows of energy-consuming output were modelled directly. Subsequently, assumptions about energy consumption per unit of physical output and share of electricity in sectoral energy consumption allowed us to derive electricity demand projections. Results were derived from a series of sectoral end-use models for the industry, transport, and buildings sectors, linked by common economic assumptions for the two scenarios. Where modelling physical equipment stocks or product flows was not possible, for example for smaller industrial subsectors, an econometric approach was followed, where demand was driven by monetary aggregates like industrial value added. The following points detail each sectoral model that drives the demand projection and further information on the sectors can be found in the respective sections.

The references at the end of each point give the major sources of the historical data that was used to calibrate the sectoral models.

- Industry: physical outputs of steel, cement, aluminium, certain primary chemicals and fertilizers (WSA, Various Years; USGS, Various Years; USGS, Various Years; UNSD, 2020; FAI, 2020; Petroleum Planning and Analysis Cell, 2020; Ministry of Chemicals and Fertilizers, 2019); industrial value added for residual sectors (RBI, 2020).
- Residential: appliance stocks of major energy consuming household appliances (NSSO, various years).
- Passenger and freight transport: stocks of cars, motorbikes, buses, trucks and other vehicles (MORTH, 2019; ITF, 2020).
- Commercial: floorspace of commercial buildings (Kumar, Yadav, Singh, & Kacchawa, 2018)
- Agriculture: modelled as a constant demand at current levels.

Figure 50 shows the results of these projections.

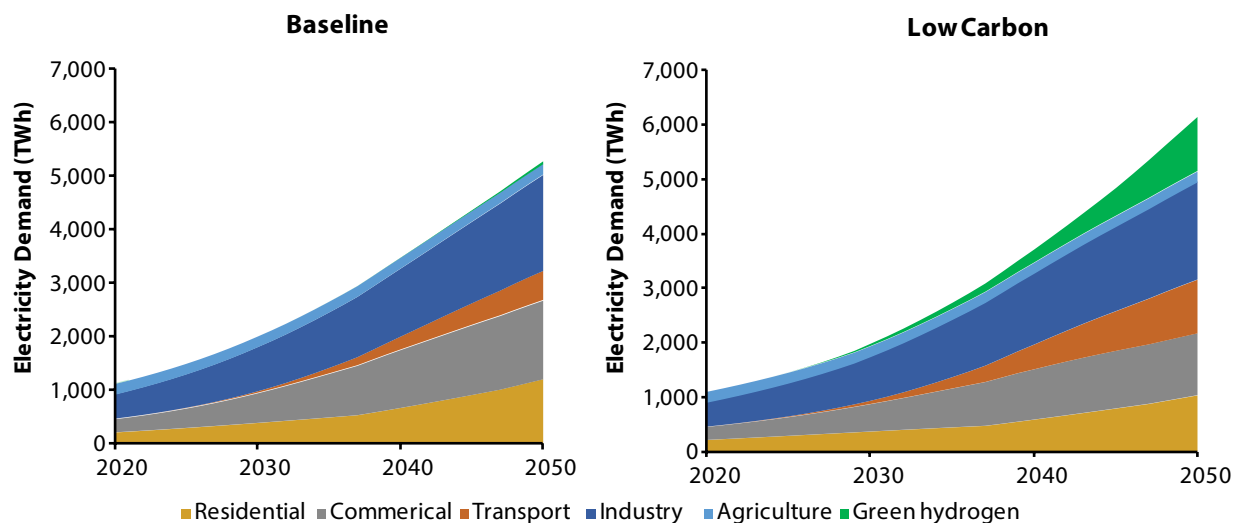


Figure 50: Annual electricity demand by major end-use sector, Baseline and Low-Carbon Scenarios

Source: TERI analysis

6.2.2 Electricity Demand Relative to Renewables Potential

India is the fifth most densely populated large country in the world, where ‘large’ is defined as having a population above 10 million. With such density, there may be concerns regarding the scale of dispersed renewables resources such as wind and solar relative to electricity demand in the context of the ambition to transition the power sector towards zero emissions. This is particularly the case if large new sources of demand, like the electro-intensive process of the production of electrolytic hydrogen, come to play a significant role in driving future demand. In order to address this question, we analysed total technical potential of onshore wind and solar PV on the basis of geospatial data covering renewables resources, land-use patterns, topography, and related criteria, based on the data sets of (NREL, 2020). Table 18 displays the key results.

Considering only barren and desert land, India's total PV potential is estimated to be in the order of 3,000 TWh, around half of India's projected 2050 electricity demand. If shrubland and sparsely vegetated eco-systems are included, the total technical potential increases to more than 15,000 TWh. There would, however, be some ecosystem loss from dedicating shrubland and sparsely vegetated landscapes to PV production. The total land area considered reaches 266,000 KM² in the case where both barren and shrubland and sparsely vegetated land areas are available for PV. This amounts to about 8% of India's total land area. These calculations assume current PV technologies, with fixed tilt utility-scale PV. More productive existing or emerging technologies such as dual axis tracking, thin film or bi-facial modules, or perovskite cells may increase PV productivity substantially by 2050, but are unlikely to change the order of magnitude of these results.

Land areas considered available for wind include cropland, as the actual land footprint of wind power is limited to the tower bases and access roads. As a result, actual land consumption for wind power is a small fraction of the total land considered available for wind power. Under these conditions, India's total technical potential for onshore wind power is in the order of 4,300 TWh. The combined onshore wind and solar PV potential is therefore in the order of almost 20,000 TWh.

Table 18: 2050 electricity demand relative to wind and solar technical potential

	Baseline Demand	Low Carbon Demand	Solar Potential Barren Land Only	Solar Potential Shrubland and Barren Land Only	Onshore Wind Potential Barren Land and Cropland	Total Solar PV and Onshore Wind Potential
	A	B	C	D	E	D + E
TWh	5,300	6,200	3,000	15,200	4,300	19,500
Total land footprint as a percent of India's total land		n.a.	~1.5%	~8%		n.a.

Source: authors, based on data from (NREL, 2020)

A number of conclusions can be drawn from this analysis. The fact that India's technical potential of onshore wind and solar is 'only' about three times larger than India's forecast 2050 demand is a cause for concern. Tapping apparently available technical potential is always a challenge, due to land acquisition delays, local opposition, and land-use conflict. Dedicating several percentage points of India's land to PV production may seem small relative to other land uses (agriculture accounts for about 46% of India's total land-use by area), but it is still substantial. It is therefore reasonable to be conservative and assume that the actual potential that could realistically be tapped is at least several multiples below the technical potential calculated in Table 19. It is also important to stress that the binding constraint may not be the absolute availability of zero-carbon electricity, but rather the rate at which it can be built, given the challenges of land acquisition in an environment where land is a scarce resource.

This has a number of important consequences for how we think about the role of hydrogen in India's energy transition. First, zero carbon electricity is going to be a scarce but paradoxically low-cost resource (assuming that barren land values don't rise to reflect scarcity). Its use must therefore be maximized by deploying it in the most efficient way possible. This means that direct electrification of end-uses should be favoured wherever possible, in order to reduce the substantial conversion losses from the production of hydrogen for end-use consumption.

Second, although electrolytic hydrogen is economically very competitive with other sources of low carbon hydrogen such as SMR with CCS, such options may have a role to play considering restrictions on the scale of zero carbon electricity. Third, today in the global fossil fuel system, there may be a role for the import of zero carbon energy carriers to India from other more land-abundant areas, such as Australia, Africa, or the Middle East. The driver of trade would not be the cost-competitiveness of production outside of India, as India is likely to be one of the most competitive regions for electrolytic hydrogen production. Rather, the driver will be the availability of land. Finally, although it is somewhat beyond the scope of this report, it also implies that India should look beyond solar PV and onshore wind at other zero-carbon power generation technologies, such as offshore wind, geothermal, hydro, nuclear and potentially even some carbon capture and storage on fossil fuels.

6.3 Hydrogen as an Electricity Storage Vector in the Power System

6.3.1 Introduction

Having surveyed the prospects for India's aggregate electricity demand and the potential for onshore wind and solar PV to meet this demand, this section turns to the role of hydrogen as a means of electricity storage in the power system. The power system must balance demand and supply in real time at all locations in the grid. The growth of variable renewable energy (VRE) sources such as wind and solar increases this inherent challenge of power system balancing. There are five options for increasing the flexibility of the power system, in order to integrate the increasing shares of VRE, mentioned as follows:

- *Demand management and demand response:* This involves modulating the timing of demand in order to increase its temporal correlation with the availability of VRE.
- *Supply-side flexibility:* Conventional dispatchable power stations based on coal, gas, or hydro can vary their output, constrained by technical operating limits, in order to compensate for the variability in VRE.
- *Storage:* Electricity can be stored at times when VRE production is high, and released in order to meet the load when VRE production is low.
- *Increasing the balancing area:* As mismatches between VRE production and load tend to decrease when the geographical balancing area is enlarged, balancing the power system across a larger area can contribute to the integration of VRE.
- *Curtailment:* Although curtailment is often seen as a deadweight loss to the power system, in high VRE systems, curtailment can be a necessary and cost-effective option for integrating high shares of VRE, where cost-effectiveness is understood at a system level relative to other grid integration options.

This section focuses on storage, although a comprehensive approach to VRE grid integration must encompass a combination of options (Spencer, Rodrigues, Pachouri, Thakre, & Renjith, 2020). Within the concept of electricity storage, there is a plethora of different applications and technologies. Applications range from very short-term frequency control, to intraday transfer of energy, to seasonal transfer of energy from high RE seasons such as monsoon to low RE seasons like the Indian winter. Technical analysis generally confirms that power-H₂-power is not a cost-effective option for short-term applications such as intraday balancing, compared to alternative technologies like li-ion batteries (Schmidt, Melchior, Hawkes, & Staffell, 2019).

Three factors are crucial in determining the economic competitiveness of power-H₂-power, which are detailed as follows:

- *Conversion losses and round-trip efficiency:* Electrolytic production of hydrogen is an electricity-intensive process with high conversion losses. Compression and standing losses of hydrogen storage may entail an energy loss in the order of 5%. Finally, conversion back into electricity in an open cycle gas turbine (OCGT) occurs at an efficiency of 35–45%, or up to 60% in the case of a more expensive combined cycle gas turbine (CCGT). Conversion efficiency of hydrogen fuel cells is between 40% and 60%, although if waste heat is captured and utilized, conversion efficiency may rise to 85% (Schmidt, Melchior, Hawkes, & Staffell, 2019). The product of these efficiencies gives a round-trip efficiency for the power-H₂-power process. Round-trip conversion efficiency for current technologies may be in the order of 33%, rising potentially to slightly less than 50% with technological improvements. Thus, converting electricity into hydrogen, or a similar chemical energy carrier like ammonia, is an inefficient process with substantial energy losses across the conversion chain.
- *Capital costs:* Given that the fuel for power-H₂-power, namely renewable electricity, is projected to be extremely cheap, the main cost component of the process is the capital cost. Annuitized capital costs are in the order of Rs. 185,000/kW (\$2,500/kW), potentially falling to less than Rs. 74,000/kW (\$1,000/kW) by 2050 (Schmidt, Melchior, Hawkes, & Staffell, 2019). In particular, there is significant cost reduction potential from electrolyzers, as detailed in Section 3.1.
- *Utilisation factor.* With high capital costs, levelized costs of storage from power-H₂-power increase rapidly in an inverse relationship with total system utilization factor. Maximizing utilization factor is therefore an important approach to keeping levelized costs down. However, this conflicts with the main application of power-H₂-power, namely seasonal storage. By definition, seasonal storage involves storing electricity for long periods of time, and smoothing the seasonal mismatch of supply and demand in high RE systems. As a consequence, the annual capacity utilization factor of seasonal storage applications is low, and hence levelized per unit costs high. The key point is that in comparison with technologies such as li-ion batteries, the per unit costs of power-H₂-power grow more slowly with decreasing utilization factor. It is this relationship between per unit costs and utilization factor that makes power-H₂-power among the most promising options for long-term storage (alongside other potential long-term chemical storage vectors, like ammonia).

With this preliminary discussion in mind, the following sections discuss the model set-up and the results of the modelling exercise that has been conducted to understand the potential role of power-H₂-power in India's energy transition.

6.3.2 Model Set-up and Key Assumptions

In order to investigate the role of seasonal storage in the Indian power system transition, a simple yet flexible model was developed, to allow the simulation of a wide range of scenarios. This range of scenarios allowed the exploration of the key drivers of the role of seasonal storage in terms of cost evolution among key system components, and in terms of the growth of VRE as a share of total generation. The following points detail the structure of the model:

- *Load:* The model took as load the 2017- 2018 hourly all India load profile.²

² Although the load profile is certain to change substantially with the growth of new end uses, there is currently not enough public data to enable a bottom up modelling of possible load profile shapes in future decades. Hence we have gone with the historical profile shape.

- *Generation technologies:* The model was set up as a stylized greenfield system with three technologies: a dispatchable generator with a marginal cost approximating the current system wide generation cost (4.5 Rs/kWh) and no capital costs, a zero marginal cost solar PV unit, and a zero marginal cost wind generation unit.
- *Storage technologies:* The model was given two storage technologies, li-ion battery storage and power-H₂-power.
- *Objective function:* The objective of the model is to minimize total system costs, including fixed costs and variable costs, while meeting hourly load across the full 8,760 hours of the year.
- *Scenario design:* Two families of scenarios were developed. In the first, the capacity of the dispatchable generator was fixed such that wind and solar were required to meet 80% of the total load. In this scenario, the costs of system components were varied to explore the drivers of the uptake of long-term storage within a high VRE system. In the second scenario, component costs were kept fixed, while the capacity of the dispatchable generator was progressively reduced and that of the wind and solar generators progressively increased. This allowed the exploration of the uptake of long-term storage as a function of increasing penetrations of VRE.

Table 19: Key capital cost assumptions in the long-term storage model

Item	Solar PV Capital Cost	Wind Capital Cost	Battery Energy Cost	Battery Power Cost	Electrolyser Cost	H ₂ Rock Store
Unit	Rs Cr/MW	Rs Cr/MW	Rs Cr/MWh	Rs Cr/MW	Rs Cr/MW	Rs Cr/MWh
2020	3.5	3.7	1.4	11	6	0.03
2050	3.0	3.2	0.7	8	3	0.01

Source: TERI analysis based on data from (BNEF, 2020; IEA, 2019; BNEF, H₂ LCOE, 2020)

6.3.3 Drivers of Long-term Storage

Figure 51 shows the share of electricity demand met from the dispatch of electricity from battery storage (blue) and electricity conversion from hydrogen storage (orange) as a function of increasing penetration of VRE in the total annual electricity generation. Twelve distinct scenarios were run, with VRE increasing in linear increments from zero per cent of total generation to 100% in the final scenario. This scenario design was repeated with cost settings in the model set at 2020 costs (left panel), and forecast 2050 costs (right panel), resulting in a total of 24 scenario runs, for each of which the model optimized system design for the full 8,760 hours of the model year (Figure 51).

Figure 51 shows that the increasing penetration of VRE necessitates the addition of storage options to balance the variability of VRE. However, the relationship between increasing VRE and the two storage technologies in the model is different. In the case of battery technology, the model starts to build and dispatch electricity from battery facilities once the combined share of wind and solar crosses about 50% in the scenario with 2020 costs, and about 40% in the scenario with 2050 cost assumptions. It should be noted that in order to keep the model solution tractable and allow multiple scenario runs, the model design ignores the complexities of power system operation related to unit commitment, technical minimum and ramp rates of conventional dispatchable generators. Other studies have shown that it is these constraints which drive the battery uptake at relatively lower levels of VRE penetration (Spencer, Rodrigues, Pachouri, Thakre, & Renjith, 2020). Thus, the results for battery technology deployment should be seen as a lower bound, and a more realistic representation of technical constraints would likely drive both earlier and higher deployment of battery technology than represented in the present scenario.

However, the most significant results relate to the uptake of long-term storage from power-H₂-power. Figure 51 shows that the model does not start to build and dispatch power-H₂-power until very high levels of VRE are achieved. At current costs, even when VRE share reaches more than 85% of total generation, only 1.5% of total demand is being met out of long-term storage from the power-H₂-power system. Even at greater than 95% shares of VRE, less than 10% of electricity demand is being met through dispatch from long-term storage.

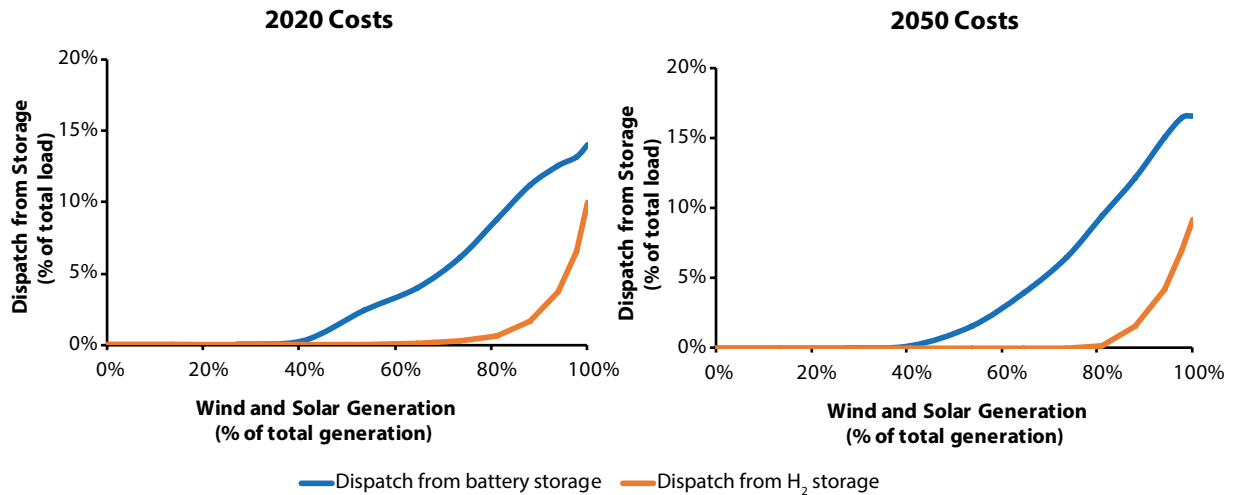


Figure 51: Uptake of short-term and long-term storage as a function of increasing VRE penetrations

Source: TERI modelling

There are several reasons for this case. First, unlike cold countries with large heating loads, India does not have substantial seasonal variation in total load. Second, a substantial part of India's cost-effective VRE potential is solar, a technology which requires intraday and not inter-seasonal balancing. Third, the high capacity cost and low round-trip efficiency of the power-H₂-power system mean that the model treats it essentially like a last resort, and deploys it only at very high penetrations of VRE and even then only to meet the last 10% of load. Fourth, the model makes use of other techniques to balance load and supply, including substantial oversizing of VRE capacities and curtailing excess output, which is cost-effective from a system perspective.

The key conclusion emerging from this analysis is that power-H₂-power (or other similar long-term forms of zero carbon chemical storage) are only required at very high penetrations of VRE in India, due to the higher reliance on a relatively less seasonal source of supply, namely solar, and the relatively unseasonal nature of load.

6.3.4 System Costs and Long-run Marginal Costs

The previous section noted that long-term chemical storage in a technology like power-H₂-power is necessary and cost-effective for system balancing only at high VRE penetrations. This section delves a little deeper into this argument by looking at two metrics of cost in the scenarios presented earlier:

- *System cost*: This represents the total summed fixed and variable cost, levelized by total electricity load.
- *Long-run marginal costs*: Electricity systems often need to install low CUF capacities in order to meet the last several hundred units of load, because demand must be met at all times. In this context, 'last'

is not understood chronologically but rather quantitatively, where the quantity referred to is the hourly load, sorted non-chronologically from lowest to highest (load duration curve). These capacities have high per unit costs because they have low utilization rates: they are only needed for a few hundred hours in the year. The model used in this section can calculate the marginal price, including fixed and variable costs, at every node for every hour of the simulation. Sorted from highest to lowest, these marginal prices are extremely convex, i.e. marginal prices rise exponentially for the last several hundred hours of load, because the model must build expensive assets to meet only these hours, resulting in high per unit costs. We can call the average hourly marginal price for these last few hundred hours as the ‘long-run marginal cost’, including both fixed and variable costs of extending supply capacities to meet the marginal load. This is not the same as short-run marginal cost, which is the variable cost of increasing generation by one unit from existing assets. In the simplest terms, long-run marginal costs can be thought of as the per unit cost of the least utilized assets built in the model in order to meet the last several hundred hours of load.

For the purpose of the analysis presented in the following paragraphs, the ‘long-run marginal cost’ is defined as the average hourly marginal price, including both fixed and variable costs, for meeting the last 10% of load hours. It can thus be understood as the per unit cost of the assets the model must build to meet the last 10% of load. Figure 52 shows the long-run marginal costs (left axis) for the 2020 and 2050 cost scenarios, as a function of increasing VRE penetration (horizontal axis). It also shows the share of total demand met from electricity dispatched from the power-H₂-power store (right axis). Although it is difficult to see from the figure, in the 2020 cost scenario, the model starts to build very small capacities of power-H₂-power earlier than in the 2050 cost scenario, namely from a VRE penetration of around 60% in the 2020 cost scenario versus 80% in the 2050 cost scenario. That the model selects power-H₂-power earlier when costs are higher in the 2020 scenario may seem paradoxical, but the reason is discussed in the following section. For the present purpose, it suffices to say that it is these capacities, although extremely small and meeting less than 1% of load, which drive the sudden jump in long-run marginal costs once the share of VRE crosses from 50% to 60% in the 2020 cost scenario. On the other hand, in the 2050 cost scenario, the model does not build power-H₂-power until the VRE share crosses 80%. This explains why the long-run marginal costs in the 2050 scenario increase in several steps. After 50% VRE penetration, long-run marginal costs are driven by the buildout of battery storage facilities with lower CUF, and the buildout of high curtailment solar and wind capacities (curtailment reduces effective output, and hence raises per unit costs). After a VRE penetration of 80%, the long-run marginal cost is driven by the buildout of power-H₂-power.

The key message, therefore, emerging out of Figure 52 is that power-H₂-power is a high-cost option, only deployed to serve the last fraction of load. Its per unit costs are therefore exceedingly high. This conclusion is consistent with the broader literature on the economics of power system decarbonization with high shares of renewables, which suggests that cost-effective options for meeting the last 10–15% of load are crucial to the overall economics of high renewable power systems.

We now turn to the overall system costs. Figure 53 presents the total system cost as a function of VRE penetration, for the 2020 and 2050 cost scenarios. To recall- total system costs represent all fixed and variable costs of all generation and storage assets in the model, levelized by the total electricity demand.

At zero penetration of wind and solar, the total system cost is determined by the variable cost of the dispatchable generator, which meets the entirety of load. This variable cost was set at 4.5 Rs/kWh in order to match the present situation of a system-wide generation cost in the order of 4.5 Rs/kWh. In the 2020 cost scenario, as the share of VRE is progressively increased, total system costs actually decline up to a penetration of around 50%. This

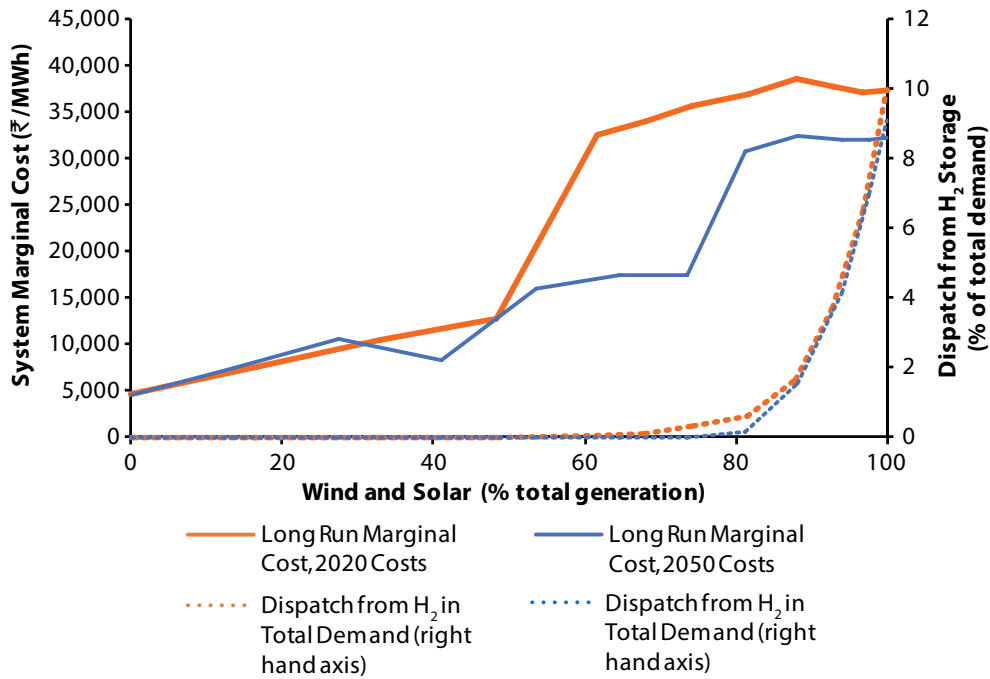


Figure 52: Per unit long-run marginal costs (left axis) vs dispatch from H₂ storage as a share of total demand (right axis)

Source: TERI modelling

is because the LCOE of wind and solar is substantially lower than 4.5 Rs/kWh, and these levels of wind and solar penetration do not require substantial curtailment or buildout of storage assets, which would raise per unit system costs. However, above 60% VRE penetration, total system costs increase as the model must start installing storage and oversizing and curtailing VRE. Above VRE penetrations of 80%, the system costs start to exceed our approximation of today’s levels. The model curtails substantial amounts of wind and solar and around a quarter of demand would be met by battery storage and expensive power-H₂-power.

The shape of the curve is similar in the 2050 cost scenario, although cost savings relative to today’s system costs are deeper and persist longer, the uptick in system costs occurs at higher VRE penetration, and even a wholly VRE plus storage system is assessed to be cost-effective relative to today’s approximate system costs. With the level of technology learning across wind and solar, batteries, power-H₂-power that we are likely to see by 2050, very high VRE systems appear economically attractive. However, it should be stressed that in both the 2020 and 2050 cost scenarios, the inflection point in the system cost curve occurs at the same time the model starts to build power-H₂-power capacities. In short, power-H₂-power is expensive and inefficient, but a necessary last resort to enable deep decarbonization of electricity. We also modelled, but do not present in Figure 53, a scenario without a long-term storage option in the form of power-H₂-power. In that scenario, system costs at high (>90%) penetrations of VRE are an order of magnitude above the system costs in the scenario with long-term electricity storage. This is consistent with the literature on the deep decarbonization of power systems, which shows that a cost-effective long-term storage is critical to keeping system costs low at high VRE penetrations.

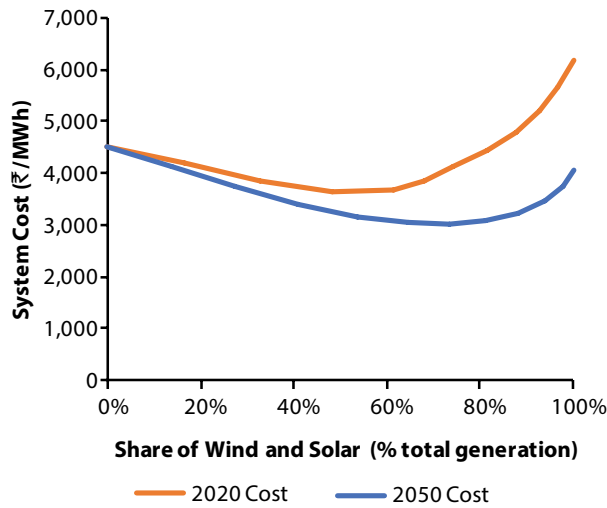


Figure 53: Total system costs as function of VRE penetration, 2020 and 2050 cost scenarios

Source: TERI modelling

6.3.5 Cost Sensitivities

In the previous sections, we explored scenarios in which technology cost assumptions were varied between only two settings, namely either 2020 or 2050 costs for all technologies in the model. This allowed us to explore the impact of progressively increasing the share of VRE in total generation on the uptake of long-term storage in the power-H₂-power system.

In this section, we do the reverse. The share of VRE generation is held constant at about 80% of total generation, while the technology cost assumptions are varied. We develop a set of 32 scenarios, in which the cost assumptions for each technology are varied between the current 2020 cost and the projected 2050 cost. These scenario permutations allow us to explore the complementarity between different technologies as well as the cost determinants of the uptake of power-H₂-power.

Results shown in Figure 54 illustrate the optimal hydrogen storage and electrolyser size, under various sensitivities. ‘Cheap’ means projected 2050 costs for that technology, or technology combination, while **Baseline** refers to 2020 costs for that technology or technology combination. Unless labelled ‘cheap’, as given in Figure 54, technologies not mentioned have been held at their **Baseline** cost value.

Under **Baseline** cost assumptions, the model builds about 40 TWh of long-term storage, equivalent to about 3.3% of total demand. The model builds about 26 GW of electrolyser capacity. In the scenario of low wind and solar costs, optimal buildout of H₂ storage and electrolyser capacity is not substantially different to the **Baseline** cost scenario. On the other hand, in the scenario of cheap wind, optimal H₂ storage size increases somewhat to 52 TWh and optimal electrolyser size to 28 GW. In the scenario of cheap battery technology, optimal H₂ storage and electrolyser capacity fall to 11 TWh and 7 GW respectively. This fall is exacerbated in the case of cheap battery and cheap solar, although the model still finds it optimal to build some power-H₂-power capacity. In the scenario of cheap electrolysers, optimal H₂ storage size jumps by an order of magnitude to 117 TWh and electrolyser capacity to 82 GW. If cheap wind is added to the scenario combination, optimal storage size increases to 127 TWh while optimal electrolyser size actually falls marginally. In the ‘cheap everything’ scenario, i.e. projected 2050 costs for all technologies, optimal H₂ storage size actually falls somewhat compared to the baseline to 30 TWh while optimal electrolyser size falls to 15 GW.

We can see from this analysis that, in the Indian power system, power-H₂-power is clearly complementary to wind power, which is the most substantial source of long-term seasonality in the demand-supply balance in a high RE system. Moreover, batteries and solar are complementary technologies, and when combined, they are to a degree partial substitutes to the wind and power-H₂-power technology combination. This is because neither India’s demand, nor the supply of electricity from solar PV, is highly seasonal. Thus, provided that solar and batteries are cheap enough together, the model is not required to build substantial amounts of long-term storage in order to compensate for an inherent long-term seasonality in the demand-supply balance. Rather, the long-term seasonality is induced by the buildout of wind. This is an important distinction to the situation in power systems in Northern Europe, for example, where there is an inherent seasonality in demand for heating and no cost-effective, large-scale complement for wind, which also displays an inherent long-term seasonality. It thus appears that the deployment of cost-effective long-term storage is not as critical to India’s low carbon power transition as it may be in other jurisdictions. Additionally, the key cost which determines the build out of long-term storage in the form of power-H₂-power is not the cost of wind, which is already cheap at today’s cost, but rather, the cost of electrolyzers.

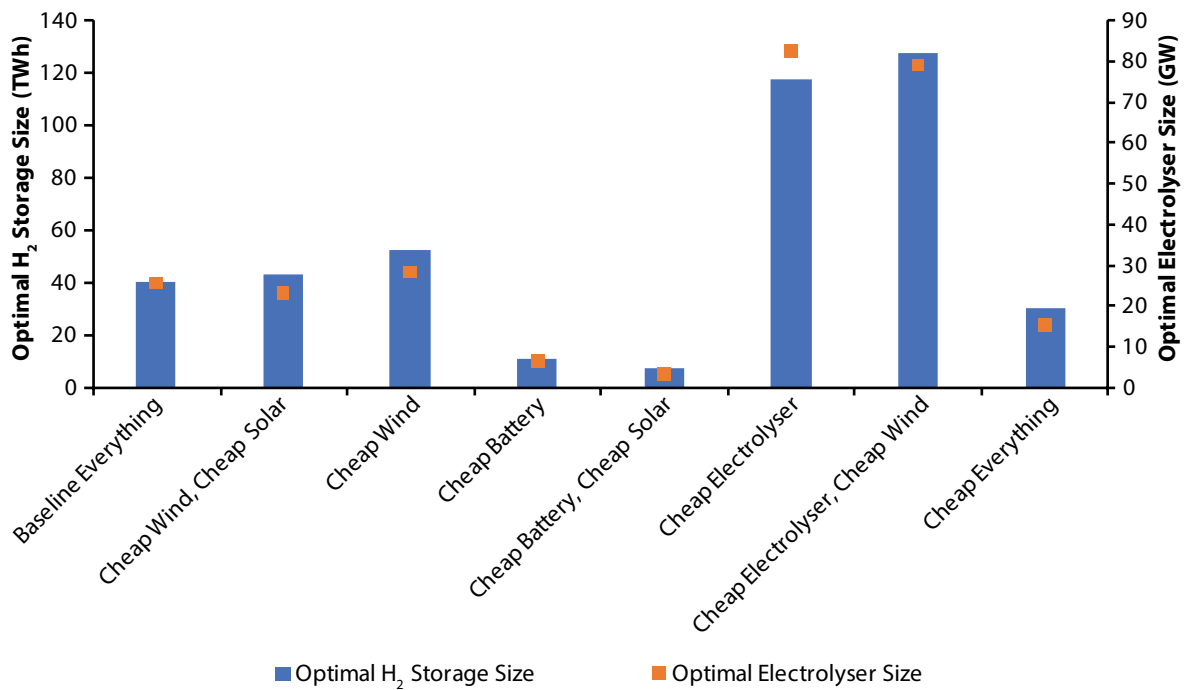


Figure 54: Technology cost drivers of power-H₂-power uptake

Source: Teri modelling

The substitution between battery and power-H₂-power storage is also illustrated in Figure 55, which shows the optimal battery size (x-axis) and optimal H₂ store size (y-axis) in all 32 scenario combinations. The strong negative correlation between the two illustrates the degree of substitution between the two technologies, depending on their relative costs and the relative costs of their complementary supply-side technologies, namely wind and solar. It is noteworthy that the two axis scales are different by three order of magnitude (TWh of H₂ storage versus GWh for battery storage). This is despite the fact that in all scenarios, dispatch from batteries contributes more to meeting annual electricity demand than electricity conversion from H₂ storage. The reason is that batteries

are used with a high annual utilization factor, cycling on an almost daily basis. This lowers the required size of the facilities in energy terms. On the other hand, the power-H₂-power facility is complementary with a seasonal resource, wind, and therefore builds out much larger capacities in energy terms, in order to fill during the season of high wind production. This illustrates again the high costs of power-H₂-power: its low annual utilization factor.

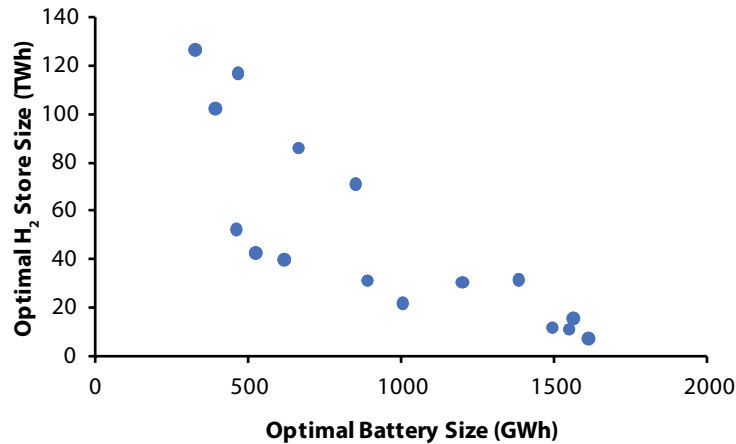


Figure 55: Substitution between battery and H₂ energy storage in all 32 cost scenarios

Source: TERI Analysis

The modelling conducted in this section has been deliberately stylized, allow the exploration of multiple scenarios (more than 56 in total). The model represents a very simplified greenfield system, without much of the technical operational constraints that power systems with high shares of VRE must overcome. However, the broad insights gained are nonetheless robust.

6.4 Conclusion

This section has surveyed the potential role of hydrogen as a long-term energy carrier in the power system. As a technology for short-term intraday storage, power-H₂-power cannot compete with other forms of energy storage, notably li-ion batteries, because of its very high capital costs and low round-trip efficiencies (Schmidt, Melchior, Hawkes, & Staffell, 2019). (Schmidt, Melchior, Hawkes, et al., 2019) Power-H₂-power is really only competitive for long-term seasonal storage applications, where the quantum of energy to be stored necessitates an energy-dense carrier like hydrogen.

This section, therefore, has developed three key conclusions. First, the assessment of electricity demand and renewables resource potential out to 2050 suggests that zero carbon electricity is going to be very cost-effective in the coming decades but may face issues related to land acquisition. This is because of the scale of demand growth that will occur, and the potential limitations of India's population density on land-use allocation for wind and solar production. It is therefore imperative that zero carbon electricity is used in the most efficient way possible. This means prioritizing direct electrification over indirect electrification with electro-fuels like electrolytic hydrogen. Second, the Indian power system is likely to require some buildout of long-term electricity storage only in very high VRE scenarios, which India is only likely to hit in the 2040s. In contrast to other power systems where both demand and supply display large long-term seasonality, India's high-quality solar PV resource and relatively

constant demand across the year (apart from a relatively small drop in monsoon) means that intraday, rather than seasonal, storage is the critical technology for enabling high penetrations of VRE. Third, power-H₂-power is an expensive technology, particularly on a per unit basis at low utilization rates. Deployment of power-H₂-power is one of the crucial drivers of the uptick in total system costs at higher VRE penetrations, as seen in Figure 53.

In contrast to the hype in India around hydrogen in the power sector, this section presents a much more nuanced picture. Hydrogen, or other forms of long-term storage, are likely to be necessary for squeezing out the last 10–20% of dispatchable fossil generation during the transition to a very high VRE system. However, such high penetrations of wind and solar are likely to only occur in the 2040s, by which time the technological landscape may be substantially different and alternative options to long-term energy storage would have emerged. This increases the uncertainty about the role of power-H₂-power in the Indian system.

A satellite night view of India, showing a dense network of yellow and orange lights representing cities and infrastructure. A dark blue rectangular overlay box is positioned in the upper left quadrant of the image.

7

CROSS-SECTORAL

Key messages

- The cost of hydrogen for different end-users can vary significantly based on their location, in particular the proximity to various renewable resources.
- To meet green hydrogen requirements of 28 Mt by 2050, approximately 150–200 GW of electrolyzers would be necessary. It is therefore important to focus on expanding India's electrolyser manufacturing capability to maximize domestic benefits.
- Green hydrogen has significant potential to displace fossil fuel imports, improving energy security, reducing import costs, and decarbonizing energy supply.

In this section, we bring together the analysis of the previous sections to develop cross-sectoral conclusions for the potential of hydrogen in India. This includes a more detailed **spatial analysis**, which highlights the locational drivers of hydrogen costs and how this might impact certain industrial clusters. We also set out the key challenges and opportunities for scaling up the **manufacturing** of key hydrogen technologies, with a focus on electrolyzers. We conclude by laying out the aggregate **energy supply** benefits of developing large-scale domestic hydrogen production, which would lead to a significant reduction in energy imports.

7.1 Spatial Analysis

7.1.1 Identifying Industrial Clusters

The location of manufacturing industries is determined by its proximity to resources, infrastructure, markets, and to other industries within the broader supply chain. Industries are drawn to a similar set of resources, such as coal or iron ore. At the same time, the complexity of industrial value chains means that industries cluster together in order to share the costs of establishing infrastructure, as well as facilitate the exchange of inputs and outputs between industries within a value chain. This is why industrial facilities display what economists call 'agglomeration effects', i.e. the benefits of geographical clustering. Figure 56 provides a map of the location of production facilities in four industries identified in the previous sections as being susceptible to the deployment of hydrogen as a fuel or feedstock. These are crude oil refineries, fertilizers, caustic soda (which produces hydrogen as a by-product), and iron and steel production. The size and opacity of the circles in each panel represent the relative size of the facility at every location for each industry. The larger and darker the circle, the more significant the facility in terms of its total production capacity as a share of that industry.

As observed in Figure 56, on the one hand, there are substantial clusters of refineries, fertilizers, and caustic soda production at two locations in Gujarat, as well as secondary clusters in a few other states (Maharashtra, Andhra Pradesh, and Tamil Nadu). On the other hand, iron and steel production facilities are generally located close to deposits of coal and iron ore, namely in Odisha, Jharkhand, West Bengal, and Chhattisgarh. Secondary clusters of iron and steel production are also located in Gujarat, Maharashtra, and Karnataka.

On the basis of the previously mentioned data, we group the facilities in these industries by physical proximity, defining all facilities within a common radius of 50 KM as belonging to one industrial cluster. We then determine the 'economic significance' of the cluster by calculating the sum of the cluster's share in the total production capacity of the four industries, divided by four in order to normalize the results according to the number of industries analysed (in this case, refining, caustic soda, fertilizers, and iron and steel). Figure 57 presents the results of this analysis. The size of the circles and the colour, from darker to lighter, describe the economic significance of the identified clusters.

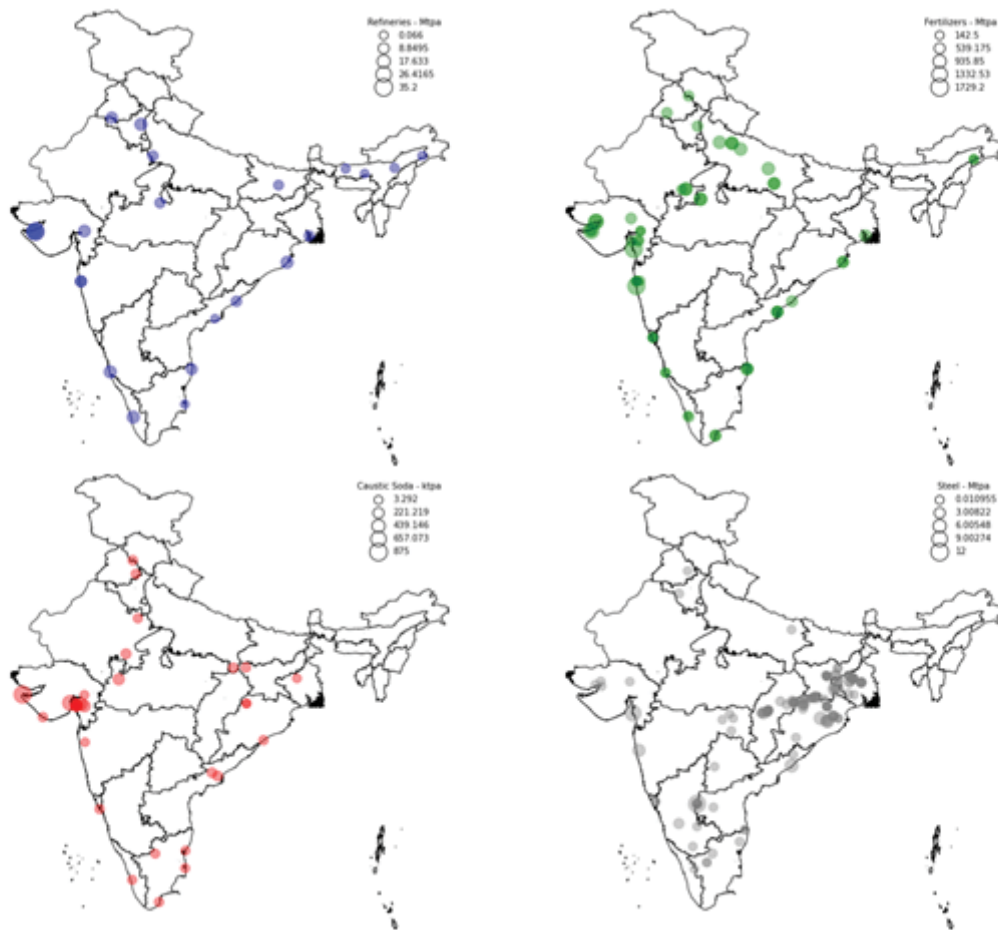


Figure 56: Geographical location of major industries susceptible to deployment of hydrogen

Source: TERI based on (Ministry of Chemicals and Fertilizers, 2020; Ministry of Steel, 2017)

Clearly, the clusters located in Gujarat, and in Odisha and West Bengal for iron and steel, represent major concentrations of productive capacities in industries that may be susceptible to the deployment of hydrogen. These clusters could offer opportunities to develop pilot projects and shared infrastructure, in order to lower the initial sunk costs of deploying hydrogen. In the following sections, we investigate, first, the access to renewable resources for these clusters, and second the cost of delivering hydrogen to two sample clusters.

7.1.2 Proximity of Clusters to High Quality Renewable Resources

As analysed in Section 3, electrolytic hydrogen appears to be the most promising cost-effective technology for the production of low carbon hydrogen in the Indian context. This production process requires large amounts of cheap low carbon electricity. For India, wind and particularly solar are likely to be the dominant sources of abundant low carbon electricity, given the cost and deployment constraints around hydro, nuclear and carbon capture and storage. We therefore analyse the availability of high-quality renewable resources in proximity to the industrial clusters identified in Figure 57. To do so, we overlay the geospatial information of cluster location seen in Figure 57 with datasets on the available technical potential for solar PV and onshore wind, considering resource availability, land-use patterns, and infrastructure proximity. The dataset for RE potential is the same as used in Section 6 (NREL, 2020).

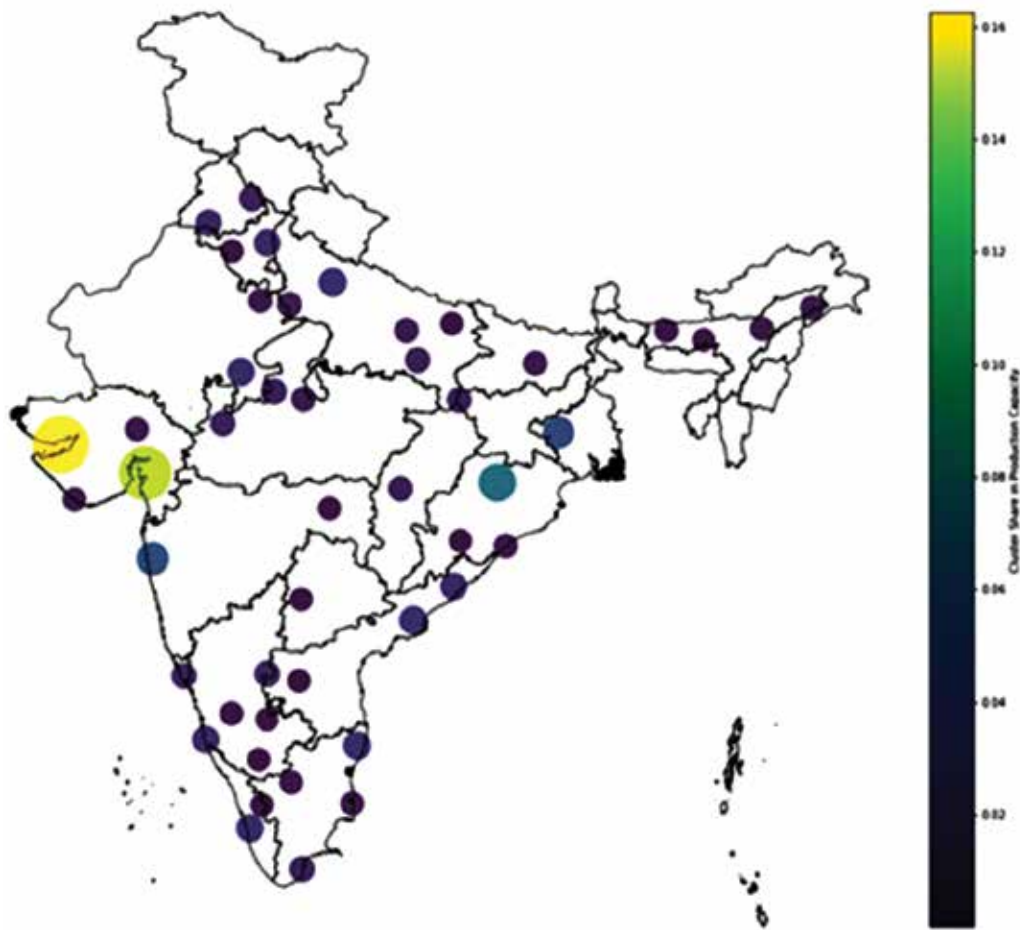


Figure 57: Industrial clusters containing industries from the chemical, petrochemical, and steel sectors

Source: TERI based on (Ministry of Chemicals and Fertilizers, 2020; Ministry of Steel, 2017)

Table 20 displays the results of this analysis. It shows the wind and solar resource that is available within 200 KM of the top 10 most economically significant industrial clusters, as determined by the methodology described in Section 7.1.1. For both solar and wind, the cluster's resource potential is broken up according to resource quality, i.e. average levels of annual irradiation or windspeed. Resource potential may be located outside of the boundaries of the state in which the cluster is located and is not exclusive between clusters. This means that resource potential allocated to one cluster may overlap with that allocated to another, if the areas defined by the radius of 200 KM from the cluster centre overlaps.

Several of the most economically important industrial clusters are within 100–200 KM of very high-quality solar resources in the order of several hundred to even a thousand TWh. On the one hand, all industrial clusters are within 200 KM of a high-quality solar resource of a scale measuring several tens of TWh. On the other hand, industrial clusters, with the exception of Gujarat, Tamil Nadu, and Maharashtra, tend to be located in proximity to lower-quality wind resources (with windspeeds <4–6 m/s).

The key point is that several of the most economically significant clusters, from the perspective of hydrogen deployment, are located close to some of India's best RE resources. But even clusters located away from India's RE rich regions, for example, iron and steel clusters in Odisha still have access to large amounts of a high-quality solar resource (5–5.5 kWh/m²/day is on par with the best locations in Southern Europe).

Table 20: RE potential within 200 KM of the top 10 most economically significant industrial clusters (TWh)

Cluster Rank	Cluster State	Solar PV				Wind		
		4.5 - 5.0 kWh/m ² /day	5.0 - 5.5 kWh/m ² /day	5.5 - 6.0 kWh/m ² /day	6.0 - 6.5 kWh/m ² /day	<4 m/s - 6 m/s	6 m/s - 8.5 m/s	8.5 - > 10 m/s
1	Gujarat	0	6	1346	0	94	29	0
2	Gujarat	0	41	450	0	193	2	0
3	Odisha	0	38	0	0	106	0	0
4	Maharashtra	0	14	349	0	88	3	0
5	West Bengal	3	31	0	0	135	0	0
6	Uttar Pradesh	0	92	0	0	188	0	0
7	Andhra Pradesh	0	32	3	0	66	1	0
8	Tamil Nadu	0	0	22	0	122	3	0
9	Kerala	0	0	7	0	56	1	0
10	Rajasthan	0	55	55	0	229	0	0

Source: TERI analysis based on data from (NREL, 2020)

Note: Two separate clusters in Gujarat make it into the India top 10.

7.1.3 Modelling Optimal System Design for Serving Industrial Demand at Selected Clusters

Having assessed the location of key industries for hydrogen deployment and their proximity to India's RE resources, we now turn to a detailed assessment of the costs of supply of hydrogen to these regions. To do so, we select two clusters, one in Gujarat and another in Odisha, as case studies. We then build a model similar to the one developed in Section 6. The following points describe the set-up of the model:

- **Objective function:** The model is given a fixed hourly demand for hydrogen consistent with the demand of a large ammonia or steel plant. This demand must be met in every hour of the modelled year. The objective function of the model is to build a hydrogen supply system that minimizes the delivered cost of hydrogen to meet this constant load. By ensuring that the model meets a constant load for 8,760 hours of simulation, we set the highest possible benchmark for the continuity of the industrial process.
- **Renewables costs and profiles:** Solar and wind investment costs were as per Table 19. Site-specific hourly wind and solar profiles were developed using the System Advisor Model (SAM), and assuming technological improvements in wind and solar CUF consistent with BNEF (2020).
- **Electrolyser costs and conversion efficiencies:** As per Table 19.
- **Storage technologies:** The model had a choice between li-ion storage or hydrogen rock formation storage, with costs as per Table 19.
- **High marginal cost dispatchable plant:** The model included a high marginal cost, fully dispatchable plant, to approximate the option of taking electricity from the grid. The marginal cost was set at 8 Rs/kWh, consistent with the high industrial tariffs paid in India. No sunk costs were associated with this resource, with all costs assumed to be reflected in the marginal price. No capacity limits were set on the amount of energy that could be drawn from this resource in any given hour of the simulation.

- *Curtailment:* The model has the option of overbuilding and curtailing RE resources. In the subsequent paragraphs, we give results for two scenarios. In one, this curtailed RE is not given a monetary value, and represents a deadweight cost to the objective function. In the other, the curtailed RE could be monetized at a low marginal cost of 2.5 Rs/kWh. This value was selected to present a conservative scenario, but also because excess RE production in the modelled system is likely to be temporally correlated with RE production in the broader Indian power system. As renewables increase their share, this temporal correlation will tend to depress the value of a marginal unit of RE supply.

The model took full account of conversion and storage losses in transforming electricity into hydrogen, storing it, and ultimately serving the final load.

Tables 21 and 22 display the results of this modelling exercise for the target cluster in Gujarat and Odisha, respectively. Several similar patterns emerge across both case studies. First, as costs decline from 2020 to 2050, the general system design in both cases transitions from a combination of wind, solar, and grid power to a system dominated by solar. The key driver of this is not solar costs, but rather electrolyser costs. Although by 2050, onshore wind and solar PV are modelled to have broadly similar annual CUFs, the supply profile for solar is much more peaky, with the CUF greater than 70% during peak solar hours and zero at night (by 2050, peak solar CUF can reach >85%). Integrating this into the hydrogen supply system requires a large electrolyser in order to absorb the large injections of solar at peak hours, and produce and store enough hydrogen for the non-solar hours. This is why, the electrolyser size increases with solar size across the projection. In turn, the very peaky solar profile necessitates a large storage facility to be able to serve the constant hydrogen load across the non-solar hours.

Second, both system designs rely on, indeed find it optimal to have, high levels of wind and solar curtailment. Early in the projection, when wind and solar costs are cheapest relative to electrolyser costs and hydrogen storage costs, it is more cost-effective to overbuild and curtail RE than to invest in additional electrolyser capacity or hydrogen storage. As electrolyser costs and hydrogen storage costs drop relative to solar and wind, it is more cost-effective to invest in electrolyser and storage capacity. That being said, even in 2050, curtailment levels remain significant.

Third, both in Gujarat and Odisha, long-term delivered hydrogen costs out of this model converge with the cost projections presented in Section 3, even when modelling a constant supply of hydrogen from variable sources of RE. There are a couple of reasons the results are likely to be on the conservative side. First, a marginal value of 2.5 Rs/kWh is on the lower side, particularly in the short-term, when RE penetrations in the broader Indian power system will be lower and the marginal system value of RE higher. Second, the requirement to serve a constant load for all hours of the year represents a stringent constraint on the system design. As noted in Section 6, in a high RE system, meeting the last 5–10% of load can often represent a substantial portion of the total system costs. The ability to curtail demand or shift it in time can therefore be very cost-effective for lowering system costs. Although heavy industry facilities operate at high CUFs, none operate at 100% CUF throughout the year due to planned maintenance. Thus, even small amounts of demand flexibility would likely lower the delivered hydrogen cost appreciably.

Fourth, the results highlight the importance of flexible electrolyser operation in the context of an extremely cheap but highly variable RE resource, namely solar. The complementarity between cheap and flexible electrolysers appears to be more important than the complementarity between solar PV and electrical storage in batteries.

This is because, fifth, the model never finds it optimal to build battery capacity to smooth electricity supply, even though battery costs in the model drop by more than half between 2020 and 2050. This is largely since the conversion loss of power to hydrogen production must be incurred anyway, and thus, hydrogen storage represents a more efficient round-trip process than battery storage of electrical energy. Moreover, the largest cost component of the hydrogen storage system is the electrolyser, which must be built anyway. The results

converge well with those of (Mallapragada, Gençer, Insinger, Keith, & O’Sullivan, 2020), who conducted a similar modelling exercise for a large number of locations in the United States, and found that battery storage was very rarely a component in the optimal system design.

Sixth, the results demonstrate clearly that India’s high industrial electricity tariffs are unlikely to be competitive with direct supply from RE. This being said, a completely islanded system does not appear cost-effective either, as the ability to purchase some high-cost grid power, and sell some unwanted RE power, are important strategies for lowering the delivered cost of hydrogen. Additionally, the possibility of hydrogen electrolyzers and fuel cells, integrated into the industrial production process, to participate in electricity markets for ancillary services or system balancing could create additional revenue streams that can help to lower the delivered cost of hydrogen to the industrial facility. How direct ‘open access’ dynamically integrates with the broader electricity grid, thus, appears to be an important issue for future policy.

Table 21: Modelled system design and levelized costs of hydrogen for an industrial cluster in Gujarat

Item	Unit	2020	2030	2050
Optimal PV	MW	41	72	86
Optimal Wind	MW	84	41	17
Optimal Electrolyser	MW	42	53	62
Optimal Battery	MWh	0	0	0
Optimal H ₂ Store	MWh	414	699	6062
Solar Curtailment	%	26%	22%	11%
Wind Curtailment	%	17%	6%	2%
Grid Consumption	%	14%	6%	0%
Levelized Cost, Scenario 1	Rs/kg	288	152	93
	\$/kg	3.89	2.06	1.26
Levelized Cost, Scenario 2*	Rs/kg	260	132	81
	\$/kg	3.52	1.78	1.10

Source: TERI modelling

* Note: scenario 2 assumes that curtailed RE can be monetized at 2.5 Rs/kWh

Table 22: Modelled system design and levelized costs of hydrogen for an industrial cluster in Odisha

Item	Unit	2020	2030	2050
Optimal PV	MW	60	119	113
Optimal Wind	MW	77	20	11
Optimal Electrolyser	MW	39	78	77
Optimal Battery	MWh	0	0	0
Optimal H ₂ Store	MWh	261	864	7231
Solar Curtailment	%	21%	10%	9%
Wind Curtailment	%	17%	23%	16%
Grid Consumption	%	26%	5%	0%
Levelized Cost, Scenario 1	Rs/kg	343	186	113
	\$/kg	4.64	2.51	1.53
Levelized Cost, Scenario 2*	Rs/kg	321	169	101
	\$/kg	4.34	2.29	1.37

Source: TERI modelling

* Note: scenario 2 assumes that curtailed RE can be monetized at 2.5 Rs / kWh

The results also show the ways in which optimal system design and delivered costs may differ between locations in India. Delivered costs are about 20% higher in the case of the Odisha steel cluster because of the lower quality RE resource availability. The results for Odisha are interesting nonetheless, because they demonstrate that even a region not known for its RE resource quality could have low delivered costs of hydrogen by 2050. Generally speaking, the poor RE resource necessitated a larger buildout of electrolyser and hydrogen storage, in order to compensate for periods of lower RE supply.

7.1.4 Sensitivity on the Cost of H₂ Storage

In the previous modelling exercise, we used the estimated cost of hydrogen rock formation storage. This is substantially cheaper and easier to scale than hydrogen storage in steel tanks. However, the potential for underground hydrogen storage has not been properly assessed in India, nor has its spatial colocation with industrial clusters. For this reason, we also assess the cost impacts, and system design impacts, of the same scenarios run earlier, but this time, substituting tank storage costs for underground storage costs.

Table 23 presents the key results. Compared to the scenario with underground storage, the modelled cost of hydrogen is somewhat higher in the scenario with tank storage. The model achieves this by increasing the scale of RE curtailment, and drawing on more electricity from the grid. In comparison with the scenarios described previously, the model also finds it optimal to build some battery storage, in order to smooth the supply of electricity to the electrolyser.

The results suggest that the presence of underground hydrogen storage is an important factor in the system design for hydrogen delivery to an industrial cluster. India's geological conditions in this regard require further research. However, given the flexibility within the model to optimize the system design (notably further RE oversizing and curtailment, increasing the share of supply from wind, or deploying battery storage), the total delivered costs of hydrogen to our sample industrial clusters do not increase significantly.

Table 23: Cluster model results with H₂ tank storage

	Unit	Gujarat 2030	Gujarat 2050	Odisha 2030	Odisha 2050
Optimal PV	MW	80	83	107	108
Optimal Wind	MW	37	26	26	23
Optimal Electrolyser	MW	57	60	70	73
Optimal Battery	MWh	0	0	0	1
Optimal H₂ Tank Size	MWh	233	267	348	756
Solar Curtailment	%	20%	22%	11%	17%
Wind Curtailment	%	10%	10%	22%	25%
Grid Consumption	MWh	14,467	8,606	21,516	8,309
Levelized Cost H₂, Scenario 1	\$/kg	2.13	1.36	2.60	1.67
Levelized Cost H₂, Scenario 2	\$/kg	1.83	1.03	2.38	1.34

Source: TERI modelling

7.2 Conclusion

This section conducted a deep-dive into the economics and system design of hydrogen supply for industrial clusters. The results are encouraging but also instructive in a number of respects. First, a detailed hourly modelling supports the conclusions of annual modelling, which ignores the intra-annual variability of RE supply, that with projected cost declines in key technologies, delivered hydrogen prices of Rs. 150/kg (\$2/kg) are perfectly

possible in the best locations by 2030, and essentially everywhere by 2050. Second, the results highlight the key technology combinations that need to come together to make this possible, in particular, the importance of flexible electrolyzers and stationary underground or tank storage of hydrogen. India's poorly understood potential for underground storage options requires further research. India's reliance on variable solar PV makes flexible and cheap electrolyzers a crucial aspect of system design, which needs to come together for low-cost industrial hydrogen to become a reality. Third, although the optimal system design took relatively small amounts of energy from the grid, such a system will still require integration into the grid, both to use electricity when required and to export excess RE when possible.

7.3 Electrolyser Manufacturing

This section will cover the manufacturing challenges and opportunities that will come with the rapid growth in demand for low carbon hydrogen. As highlighted in Section 3, we view green hydrogen as having the highest potential for low carbon hydrogen generation in India due to the low costs of renewable electricity. As such, we will explore the current electrolyser market and the potential for India to develop a competitive domestic industry, making best use of competitive advantages in skilled, low-cost labour, and large domestic demand.

7.3.1 Current Status

At present, Europe is a leader in the global alkaline electrolysis industry with two major manufacturers, Nel Hydrogen and Hydrogenics, supplying markets around the world. Other major suppliers, such as ThyssenKrupp, have serious plans for scaling up electrolyser manufacture, expanding beyond existing markets in the chlor-alkali industry (E4tech, 2019). For PEM manufacture, Siemens, ITM Power and Nel Hydrogen (through its purchase of Proton Onsite) are the main market leaders.

China, Japan, and the US are also developing production capacity but are currently less active in the global market than some of the bigger European players. That said, China has a significant cost advantage over these other regions, already reporting costs of around \$200/kW, and has the potential to undercut other manufacturers if it chooses to scale up exports (BNEF, 2020). Whilst the exact costs are disputed, based on expert discussions for this report, it is clear that China operates at a significant cost advantage over manufacture in the rest of the world, driven by lower labour and material costs, economies of scale, and a strong pipeline of projects.

India does not yet have any major electrolyser manufacturers, although there is significant research activity within leading institutions on various electrolyser technologies. The domestic electrolyser market is largely being met by Asahi Kasei Chemical (Japan) and ThyssenKrupp (Germany), which supply the chlor-alkali industry.

7.3.2 Challenges

7.3.2.1 International Companies Have a Head-Start

It is clear from the current status of the electrolyser market that major international companies have developed a strong head-start in the manufacture and sale of electrolyser technologies around the world. It will be challenging for an Indian company to break into this market, as these suppliers are often part of a larger engineering company with a strong global footprint and expertise throughout the hydrogen supply chain, for example, Siemens.

7.3.2.2 Scale of Investments Required

To deliver on an electrolyser manufacturing industry of this scale, the scale of investment required will be significant. Taking the maximum potential scenario, whereby all low carbon hydrogen under the **Low Carbon**

scenario is provided by electrolyzers, Rs. 330,000–440,000 Cr (\$45–60 bn) would be required between now and 2050. This will require mobilizing public and private, international and domestic, development and climate funds to deliver on this scale of deployment.

7.3.3 Opportunities

7.3.3.1 Market is Still at an Early Stage

Whilst these countries have a clear lead in electrolyser manufacture, the market is still relatively small, with plants at the 10 MW scale. To achieve the scale of production to meet the rapidly expanding demand for green hydrogen, GW-scale plants will be required. As manufacturers take steps to ramp up production, India should position itself as an important hub for electrolyser production, capitalizing on access to a large, local market, as well as low-cost, skilled labour.

7.3.3.2 Leverage Domestic Research Expertise

Joint ventures between electrolyser manufacturers and domestic research institutions will help increase the flow of information between early-stage R&D and commercial-scale manufacture, which is currently limited in India. Historically, there has been significant support from the Ministry of New and Renewable Energy, which in 2016 set out a comprehensive plan for increasing R&D activity to support hydrogen technologies (MNRE, 2016). Indian industry is also making considerable efforts to establish a hydrogen economy in India. Major companies, such as Indian Oil Corporation Limited (IOCL), NTPC, Reliance Industries, and Adani Group are keen to expand the use of hydrogen in the economy (S&P Global, 2020). Leveraging this existing public and private expertise will help the rapid development of an industry that is cognisant of the latest technology developments.

7.3.3.3 In Line with Current Policy Aims

The Government of India has set out clear targets to boost domestic manufacturing in order to reduce the dependence on imported goods and materials. This is encapsulated within both the ‘Make in India’ initiative, as well as the more recent aspiration of ‘Atmanirbhar Bharat’ (self-reliant India). Developing a domestic manufacturing industry in what is set to be a keystone technology for the clean energy transition aligns well with the current government’s policy aims, and suggests more direct policy support could be possible. It is also the case that deploying this technology displaces imported energy products, such as oil and natural gas, further emboldening this narrative.

7.3.4 Energy supply

In assessing the role of hydrogen in India’s energy transition, it is important to consider how this will change the country’s overall energy supply. This includes the extent to which hydrogen could displace energy imports in the future, based on our sectoral analysis.

In 2018, India’s total energy supply was 919 Mtoe, out of which, 574 Mtoe came from domestic production and the remaining 346 Mtoe was imported. This equates to 38% of India’s energy supply being imported, standing at 30% for coal, 85% for oil, and 50% for natural gas (Figure 58). Around one-third of this energy is lost during its transformation to final end-use applications, such as the conversion of coal to electricity in coal-fired power stations. Industry (34%) is the largest end-use sector, followed by residential (29%), transport (17%), other (16%), and services (4%) (IEA, 2020).

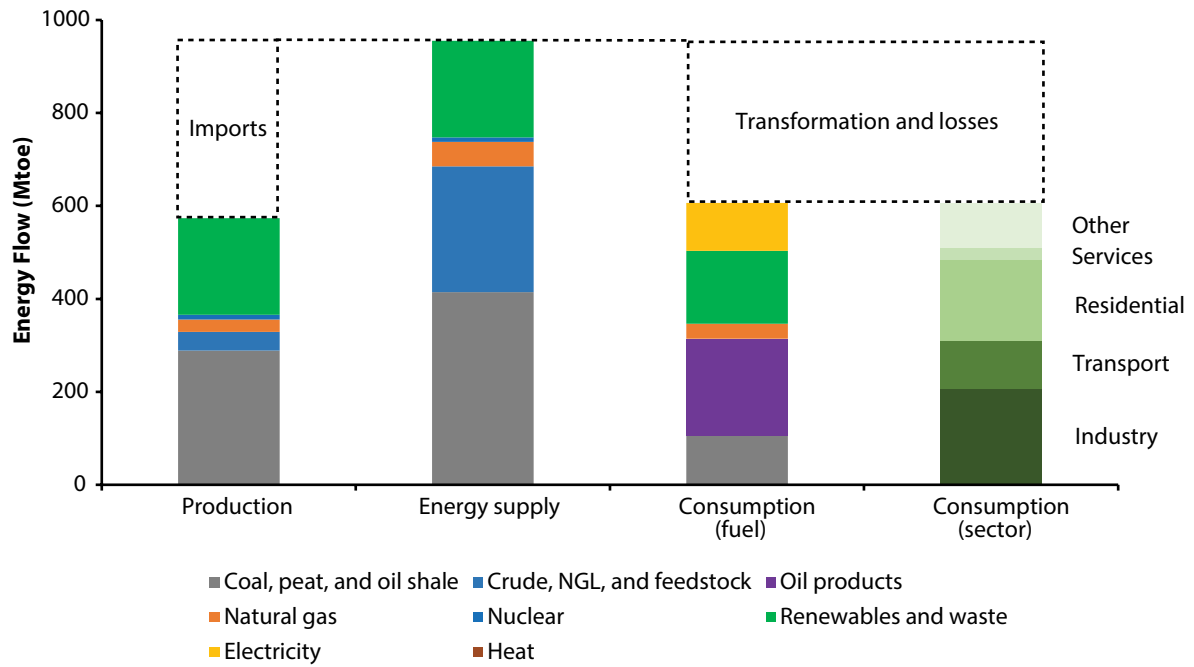


Figure 58: Energy supply and consumption by fuel and sector, 2018

Source: (IEA, 2020)

By 2050, we can expect hydrogen to displace large quantities of imported fossil fuels. Based on our sectoral analysis, we are able to separate the impacts of increased low carbon hydrogen use on energy consumption in the three sectors covered earlier: transport, industry, and power. Figure 59 shows the impact of increased hydrogen use on coal, oil and natural gas in our **Low Carbon** scenario. There is a significant decrease in the import of coal, which is primarily coking coal in the iron and steel sector. A small amount of coal would also be displaced in the power sector, if we assume flexible coal-fired generation is replaced with hydrogen. Just under 10 Mtoe of oil would also be displaced by an increased role of hydrogen in the transport sector. This is relatively low due to

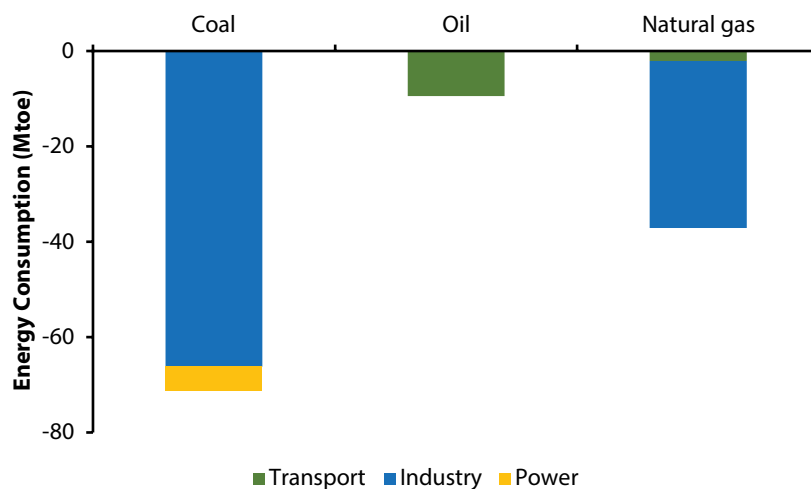


Figure 59: Reduction in fossil fuel consumption in the Low Carbon scenario, 2050

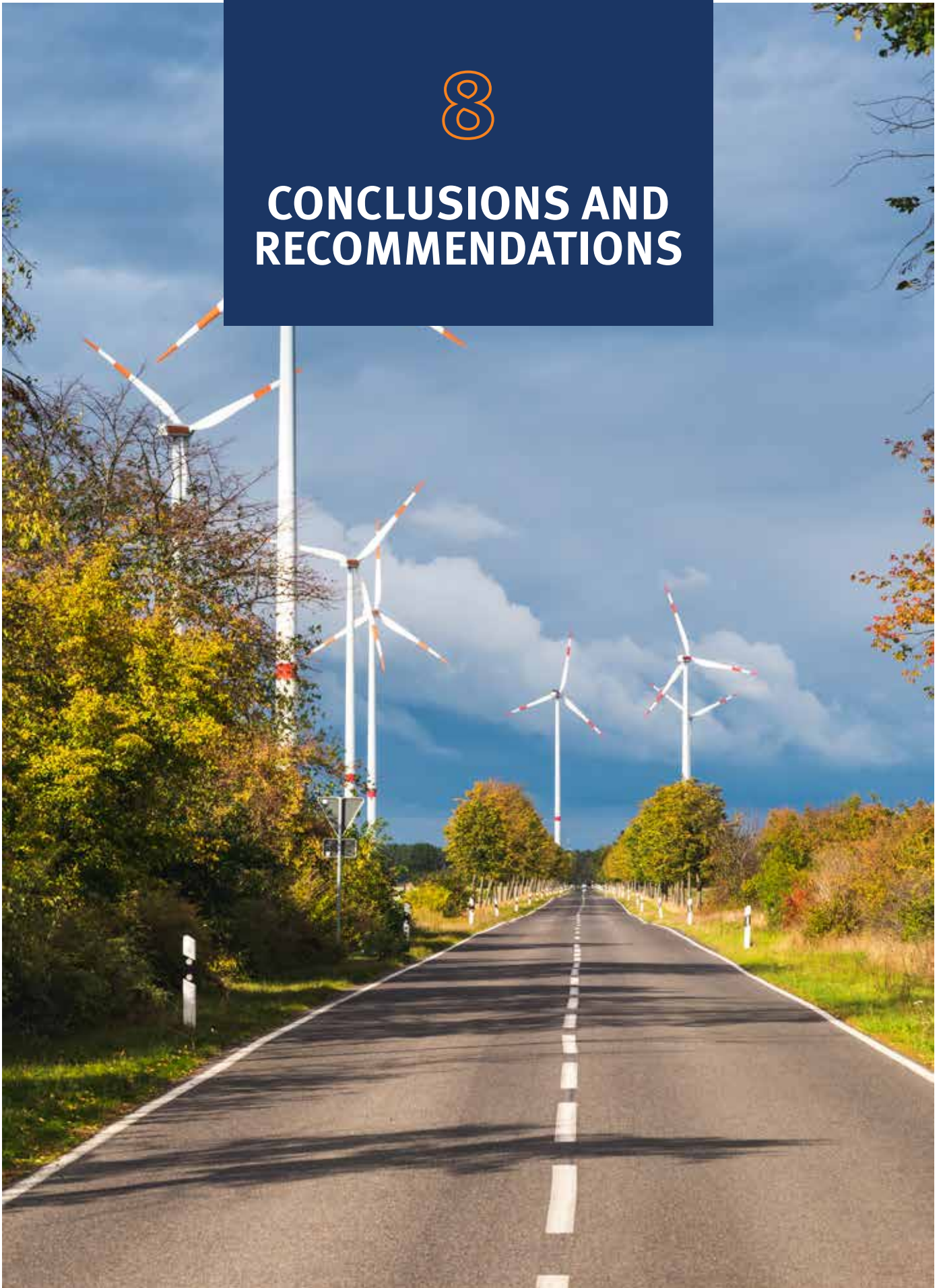
Source: TERI analysis

the dominant role of electric vehicles, which displace around 55 Mtoe in the **Low Carbon** scenario. A significant amount of natural gas is displaced by industry switching from natural gas to green hydrogen, led by ammonia production, followed by refineries, and finally methanol. Collectively, a switch to green hydrogen in these sectors displaces 35 Mtoe of natural gas, which is greater than India's total consumption of 32 Mtoe in 2018. Some natural gas use in transport would also be displaced by a switch to hydrogen, although again, this is relatively low due both to the role BEVs and the small role natural gas plays as transport fuel.

Assuming these fuels would all otherwise be imported – which is highly plausible given coking coal, oil, and natural gas are all mostly imported today – costs of imports would fall significantly. Based on central assumptions on long-term fuel prices, increased use of hydrogen in line with our **Low Carbon** scenario could reduce costs of imports by just under \$20 bn a year by 2050. This assumes an imported coking coal price of \$150/tonne, an imported oil price of \$40/barrel, and an imported natural gas price of \$10/mmbtu.



CONCLUSIONS AND RECOMMENDATIONS



Based on a comprehensive understanding of hydrogen technologies, as well as a detailed sectoral assessment of where hydrogen could be used, it has been possible to more accurately quantify the potential role of hydrogen in India. The aim of such an assessment has been to provide an evidence base for the government and businesses to better understand how hydrogen can play a role in strategies for energy transition. There is currently a lot of hype around hydrogen and its potential role in future energy systems. The conclusions of this report aim to harness this hype towards a rapid acceleration of energy transition in India.

1. The potential scale of **hydrogen demand** growth in India is significant, growing two-fold in our **Baseline** scenario or five-fold in our **Low Carbon** scenario.
2. Costs of **green hydrogen** will start to compete with fossil fuel-derived hydrogen latest by 2030.
3. Hydrogen **should be targeted** at those sectors where direct electrification is not well-suited. Renewable electricity will be low cost but the speed of its deployment may be constrained by land acquisition, so it is important that it is used in the most efficient way possible.
4. In **transport**, battery electric vehicles will be competitive across all segments, limiting the role of hydrogen to long-distance and heavy-duty applications.
5. In **industry**, hydrogen already plays an important role as a chemical feedstock and low carbon hydrogen could start to be competitive by 2030.
6. In **power**, hydrogen could be a cost-effective way of providing inter-seasonal storage in a high variable renewable electricity system from 2040.
7. The development of hydrogen technologies will depend on **locational factors**, such as access to renewable resources.
8. India should be proactive in developing and deploying hydrogen technologies, to **indigenize manufacturing** and maximize domestic benefits.
9. Scaling up the use of domestically produced hydrogen could significantly reduce **energy imports**.
10. To accelerate the adoption of hydrogen technologies in India, a step-change in **government policy and business actions** is required.

In order to accelerate the uptake of hydrogen technologies in India, both public and private actions are required. This would help ensure that India moves from a position of ‘technology-taker’ to a position of a globally competitive ‘technology-maker’. This would also deliver significant environmental benefits, including GHG emissions reduction and local air pollution benefits. We recommend the following measures to accelerate this shift.

8.1 Recommendation 1: Greater Cross-Sectoral Coordination

It is clear from the analysis in this report that hydrogen is an important cross-cutting solution, which will likely play a role in reducing emissions from a number of sectors. To date, activity on hydrogen in India has largely been focused on individual use-cases, such as hydrogen buses, or supplying industrial facilities. To maximize the benefits of hydrogen technologies, a cross-sectoral approach is required, which understands the case for shared infrastructure, aggregate energy system impacts, and overlapping ministerial responsibilities. For example, a single hydrogen production hub could supply a number of end-users, lowering the costs of supply. In terms of energy system impacts, it is important to understand how hydrogen production would reduce certain energy

imports, whilst increasing domestic electricity demand. Finally, within the government, the development of hydrogen technologies falls under the remit of several different ministries, including the Ministry of New and Renewable Energy (MNRE), the Ministry of Petroleum and Natural Gas (MoPNG), the Ministry of Power (MoP) and the Ministry of Science and Technology (MST). On the demand-side, the Ministry of Road Transport and Highways (MoRTH), the Ministry of Steel, the Ministry of Heavy Industries and Public Enterprise (MHIPE), and the Ministry of Chemicals and Fertilizers (MoCF), would also have an interest. To coordinate activity between this large number of ministries, a separate institutional set-up would be required to provide leadership and synchronize initiatives.

8.2 Recommendation 2: Shift from R&D to Commercialization Support

The Government of India and major Indian companies have already committed some funding to early-stage research, as well as demonstration projects for a number of hydrogen technologies. To date, this has principally been focused at the R&D stage of the hydrogen technology innovation chain, with minimal success in terms of commercializing technologies (Figure 6o). Over the coming years, there should be a greater focus on demonstrating hydrogen technologies in the real world, in partnership with industries.

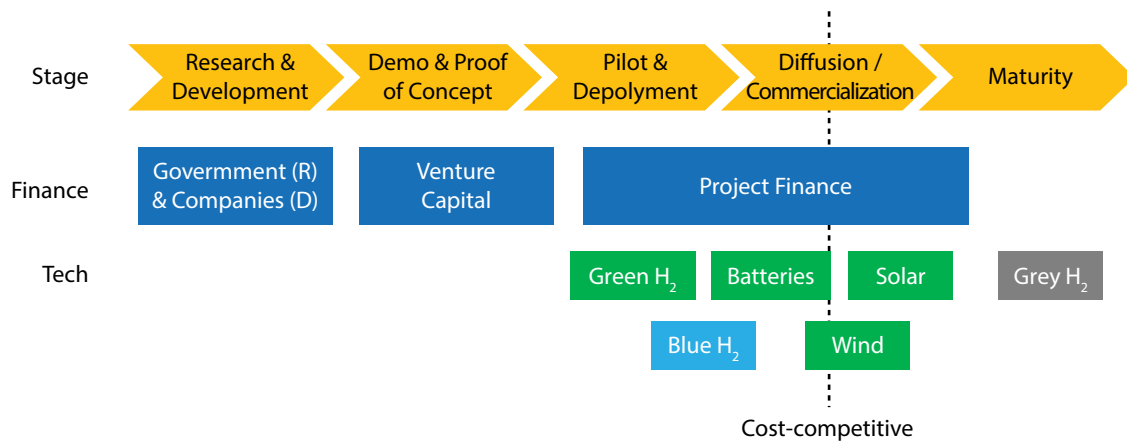


Figure 6o: Innovation chain, finance requirements and key clean energy technologies

Source: Adapted from (Mazzucato & Semieniuk, 2017)

This would require the development of public-private partnerships to de-risk initial deployment. This includes private investors evaluating the hydrogen opportunities in their portfolios and launching early-stage innovation funds to scale up production (ETC, 2020). As technologies are proven in the Indian context, further deployment support may be required to bridge the gap between low carbon technologies and incumbent fossil fuel technologies. As indicated in our sectoral analysis, in most cases, this public support would in most cases be temporary, as the green hydrogen technologies reach cost parity with fossil hydrogen. Only by moving to deployment-led support can India achieve rapid cost reductions in key hydrogen technologies, as has been the case with solar PV, onshore wind, and batteries. Such activity would also align well with the ‘Make in India’ and ‘Atmanirbhar Bharat’ initiatives, through championing domestic technology providers and ultimately reducing dependence.

8.3 Recommendation 3: Introduce an Emissions Penalty

An important tool to help accelerate the switch to low carbon technologies is the introduction of a penalty on CO₂ emissions. This could be in the form of regulations limiting emissions from certain processes or end-uses, or through the imposition of a carbon tax. Introducing an emissions penalty would help level the playing field between green hydrogen and grey hydrogen sooner than relying on prevailing trends. This could stimulate the industry in the early 2020s, helping India keep abreast of clean energy technologies by further supporting deployment (Figure 61).

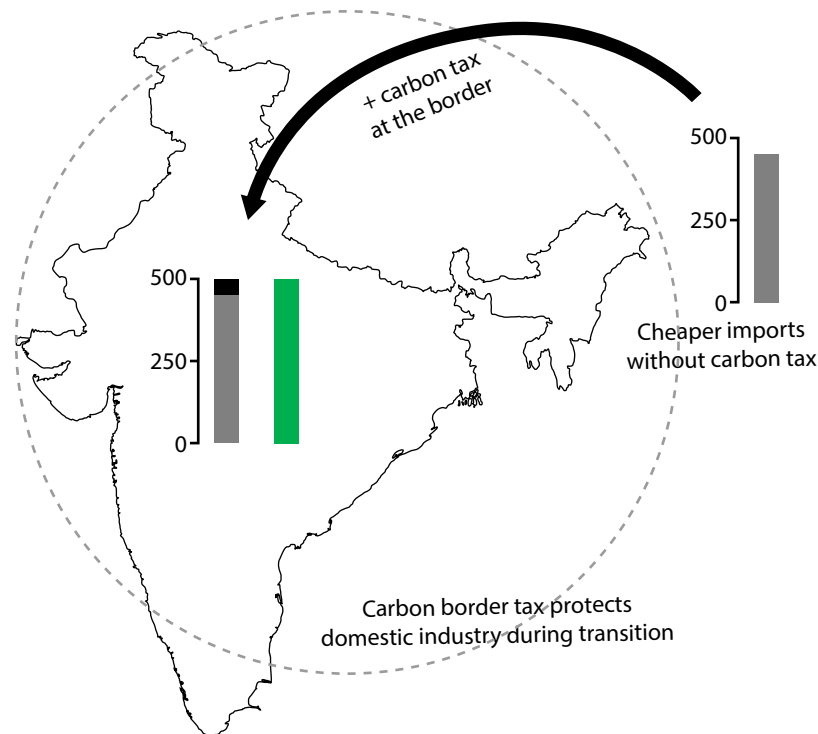


Figure 61: Example of a carbon border adjustment

Source: TERI

A potentially important supplementary measure to an emissions penalty such as a carbon tax would be a carbon border adjustment (CBA). This would ensure that the higher costs imposed on Indian industry from such a measure would not put them at a competitive disadvantage with ‘dirty’ imports from other countries, which do not pay such a tax. At the border, an additional tax would be placed on imported products, at the same level as domestic products, preventing an undercutting of Indian companies. Such a policy measure is being taken forward by the European Commission, with expected implementation in the early 2020s.

8.4 Recommendation 4: Create Markets through Mandates and Standards

Alongside punitive measures to restrict emissions from certain processes or end-uses, it would also be beneficial to support products produced with low carbon hydrogen through green product standards. This would allow consumers to differentiate between products made using environmentally sustainable methods, versus polluting

methods, thereby creating new markets for such products. As a result of this differentiation, producers could charge a premium to account for the higher initial costs of production, recognizing a greater demand from certain consumer segments. Within India, the Confederation of Indian Industry (CII) is already developing such standards, under their 'GreenPro' initiative (CII, 2019). Internationally, similar initiatives are moving ahead in certain sectors, with 'SteelZero' aiming to bring together a critical mass of consumers (e.g. automobile manufacturers and construction companies) to purchase low emission steel (ResponsibleSteel, 2020).

8.5 Recommendation 5: Targeted Industry Activity

Whilst the preceding recommendations have focused largely on government policy to accelerate the transition to the use of low carbon hydrogen, private sector companies will also play a vital role in advocating these measures, as well as targeting activity more directly under their control. This includes establishing international collaborations with leading technology providers, which can support the rapid deployment of hydrogen technologies in the near term. One such example could be the establishment of a low carbon steel plant, bringing together international players that can provide the required technologies. These partnerships have been successful in the past, for example, the collaboration between India and Japan on industrial energy efficiency technologies. It will also be beneficial to coordinate existing private sector R&D activity through consortia to solve similar problems or develop demonstration projects, which require multiple companies along a supply chain, or within a cluster. This approach has been taken elsewhere, for example, in the UK, where a net-zero cluster is being established in Teesside, making use of hydrogen technologies (Net-Zero Teesside, 2019).

9. FURTHER WORK

Whilst this report has attempted to provide a comprehensive technical overview of the key hydrogen technologies and the main end-use segments, there are several areas that would require further work. This includes the following:

- The potential role of biomass in producing hydrogen, taking into account the limits of sustainable biomass supply.
- More comprehensive studies on the potential CO₂ storage and utilization options for India, taking into account the location of different CO₂ sources.
- A more comprehensive study on the electrification of industrial processes, primarily heat. This will help us understand hydrogen's role in this segment.
- The role of hydrogen in the petrochemicals, shipping, and aviation sectors for India.
- More in-depth analysis and feasibility studies for promoting hydrogen in real use-cases across different sectors.
- Detailed mapping of underground storage options for hydrogen, and research into potential for cost reductions in overground hydrogen tanks.

10. ANNEXES

Annex A – Academic Institutions

Institution	Projects
IIT Delhi	<ul style="list-style-type: none"> Conducting studies on catalytic decomposition of sulfuric acid in the I-S process, Bunsen reactor for production of sulfuric acid production and HI using electrochemical cell etc.
IISc, Bangalore	<ul style="list-style-type: none"> Using biomass gasification for fuel cell applications. Multi-fuel gasification system which uses woody biomass or biomass briquettes. Developing semiconductor Nano-composites for Photo-catalytic water splitting under solar light irradiation etc.
IIT Madras	<ul style="list-style-type: none"> Electrocatalysis and photocatalysis for hydrogen production, generation of solar hydrogen.
IIT Guwahati	<ul style="list-style-type: none"> Exploring production of Bioethanol and Biohydrogen from lignocellulosic biomass in a fluidized-bed reactor.
IIT Kharagpur	<ul style="list-style-type: none"> Mission mode project will explore hydrogen production using biological routes.
IIT Kanpur	<ul style="list-style-type: none"> Developing photoelectrochemical water splitting and fuel cells.
IIT Hyderabad	<ul style="list-style-type: none"> Exploring the use of non-thermal plasma assisted direct decomposition of H₂S into H₂ and S. Using low temperature plasma catalysis to transform greenhouse gases such as methane and CO₂ into syngas/H₂.
IIT Indore	<ul style="list-style-type: none"> H₂ generation through catalytic route.
CSIR-NEERI	<ul style="list-style-type: none"> Development of hydrogen supply system through Liquid Organic Hydrides.
IIT (Banaras Hindu University)	<ul style="list-style-type: none"> Photocatalysis for water splitting, conversion of methanol to hydrocarbons. Catalytic cracking of methane.
UPES, New Delhi	<ul style="list-style-type: none"> Establishment and demonstration of H₂ production and utilization facility through photovoltaic-electrolyser system at NISE, Gwalpahari Survey on inventory and quality of by-product H₂ potential in selected major sector in India.
IICT, Hyderabad	<ul style="list-style-type: none"> Methanol reformer to produce 10kL/hr paired with a 10kW fuel cell and 50 kL/hr paired with a 50kW fuel cell. Catalysts for reformation of glycerol. H₂ generation through biomass derived from glycerol.
C-MET, Pune	<ul style="list-style-type: none"> Exploring photocatalytic decomposition of toxic H₂S. Developing a prototype photo-reactor for hydrogen production from H₂S under natural sunlight. Photocatalysts development.
NIT, Calicut	<ul style="list-style-type: none"> Investigation on bio-hydrogen production using the thermochemical method.
NIT Rourkela	<ul style="list-style-type: none"> H₂ production from biomass and waste using fluidized bed gasifier.
CSIR-IMMT, Bhubaneswar	<ul style="list-style-type: none"> Developing transition metal tantalates and oxynitrides for water splitting. Functional hybrid nano structures for photo electrochemical water splitting.
ICT, Hyderabad	<ul style="list-style-type: none"> Generation of H₂ from biomass-derived glycerol.

Institution	Projects
ICT, Mumbai	<ul style="list-style-type: none"> • Analysis for Cu-Cl thermo-chemical production process. • ICT-OEC process for Cu-Cl thermochemical hydrogen production, reaction of metals with HI etc.
CECRI, Karaikudi	<ul style="list-style-type: none"> • Oxidation of CuCl and recovery of Cu, CuCl, HCl system for preparing CuCl₂ and H₂ electrodes and electrolytes for water electrolysis.
ARCI-CFCT, Chennai	<ul style="list-style-type: none"> • Novel electro catalysts, depolarizers for water electrolysis, sea-water electrolysis.
The Energy and Resources Institute	<ul style="list-style-type: none"> • Technology packages for woody and briquetted biomass, bioreactor facility for bio-H₂ production.
Naval Material Research Laboratory, Mumbai	<ul style="list-style-type: none"> • Bio- H₂ with chemical fuel cells for electricity generation, hydrogen generation using ATR.
NIT Raipur	<ul style="list-style-type: none"> • Electrolytic cell design for bio-H₂ production from leafy biomass by electro-hydrogenesis.
NIT Tiruchirappalli	<ul style="list-style-type: none"> • Combined pyrolysis and steam gasification to establish multi-fuel Quraishy production.
CSIR-IIP, Dehradun	<ul style="list-style-type: none"> • Open loop thermochemical S-I cycle of H₂S split for carbon-free H₂ production in petroleum refinery.
OEC, Mumbai	<ul style="list-style-type: none"> • Thermochemical H₂ production, and I-S and CuCl cycle for H₂ production.
CIMFR, Dhanbad	<ul style="list-style-type: none"> • H₂ production using renewable and fossil fuel based liquid and gaseous hydrocarbons by non-thermal plasma reforming.
Sardar Patel Renewable Energy Research Institute, Gujarat	<ul style="list-style-type: none"> • Dual fuel and thermal application, forced, and natural drafts biomass gasification process.
IACS, Kolkata	<ul style="list-style-type: none"> • Hydrogen Evolution Reaction (HER) by the FE-FE, hydrogenase enzymes, graphene oxide modified aza terminated ITO-supported graphene as electrode material, catalyst development. • Bio-inspired catalysts for reversible conversion.
ONGC	<ul style="list-style-type: none"> • Thermochemical hydrogen generation.
University of Rajasthan	<ul style="list-style-type: none"> • CNT doped polymeric membranes for hydrogen Purification.
JNTU, Hyderabad	<ul style="list-style-type: none"> • H₂ production through bio routes, PEM electrolysis, catalysts for hydrogen from glycerol. • Studies on the novel ways of enhancing CO₂ utilization in catalytic oxidative dehydrogenation reactions.
SPIC Science Foundation Chennai	<ul style="list-style-type: none"> • PEM methanol electrolyser for production of 1 NM³/ hr of H₂.

Institution	Projects
Shiksha 'O' Anusandhan University, Bhubaneswar	<ul style="list-style-type: none"> • Porous graphene modified metal oxide photo anode for electro-chemical water splitting.
Thapar University, Patiala	<ul style="list-style-type: none"> • Reforming of biogas for utilization in CI engine under dual fuel mode.
DEI, Agra	<ul style="list-style-type: none"> • Synthesis and characterization of nanostructured metal oxides and quantum dots for solar hydrogen production, photoelectrochemical generation.
IIT (BHU) Varanasi	<ul style="list-style-type: none"> • H₂ production with gasification and solar energy in Center of Excellence in Energy and Resources Development, Mechanical Engineering Department.

Source: (Department for Science and Technology, 2020)

Annex B – Technology Providers

Company	Technology	Country	Products
NEL ASA	PEM and alkaline electrolysis	Norway	Electrolysers, fuel stations, storage
ITM Power plc	PEM electrolysis	United Kingdom	Electrolysers, fuel stations
Thyssenkrupp	Alkaline electrolysis and Chlor-alkaline electrolysis	Germany	Electrolysers
H-Tec Systems GmbH	PEM electrolysis	Germany	Electrolysers, stacks
Hydrogenics Corp.	PEM and alkaline electrolysis	Canada	Electrolysers, fuel stations, fuel cells, storage
Siemens AG	PEM	Germany	Electrolysers
ITM Power Plc	PEM electrolysis	United Kingdom	Electrolysers, fuel stations
McPhy Energy S.A.	Alkaline and PEM electrolysis	France	Electrolysers, fuel stations, storage
Cummins	PEM, alkaline fuel cells, and electrolysers, invested in development of solid oxide fuel cells	United States	Fuel cells, electrolysers,
Proton Onsite	Acquired by Nel Hydrogen in 2017	United States	
Teledyne Energy Systems Inc	Fuel cell power systems	United States	Electrolytic, thermoelectric, battery and fuel cell systems
AREVA H2Gen	PEM electrolysers	France	Electrolysers,
Toshiba	Alkaline electrolysis and solid oxide electrolysis (demonstration stage)	Japan	Electrolysers

Company	Technology	Country	Products
<u>Asahi Kasei</u>	Chlor-alkaline electrolyzers, PEM membranes	Japan	Electrolyzers, PEM membranes for fuel cell, electrolyser and redox flow battery applications
<u>Hitachi-Zosen</u>	PEM electrolyzers	Japan	Electrolyzers
<u>Kobelco</u>	PEM and alkaline electrolyzers	Japan	Electrolyzers
<u>Honda</u>	PEM electrolyser-based home refuelling station	Japan	Electrolyser -based home refuelling station
<u>Peric</u>	Alkaline electrolyzers	China	Electrolyzers
<u>Ningbo Heli Hydrogen Energy technology</u>	Alkaline electrolyzers	China	Electrolyzers
<u>Tianjin Mainland Hydrogen Equipment</u>	Alkaline electrolyzers	China	Electrolyzers
<u>Suzhou Jing Li Hydrogen Production</u>	Alkaline electrolyzers	China	Electrolyzers

Sources: (E4tech, 2019; First Berlin Equity Research, 2019)

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