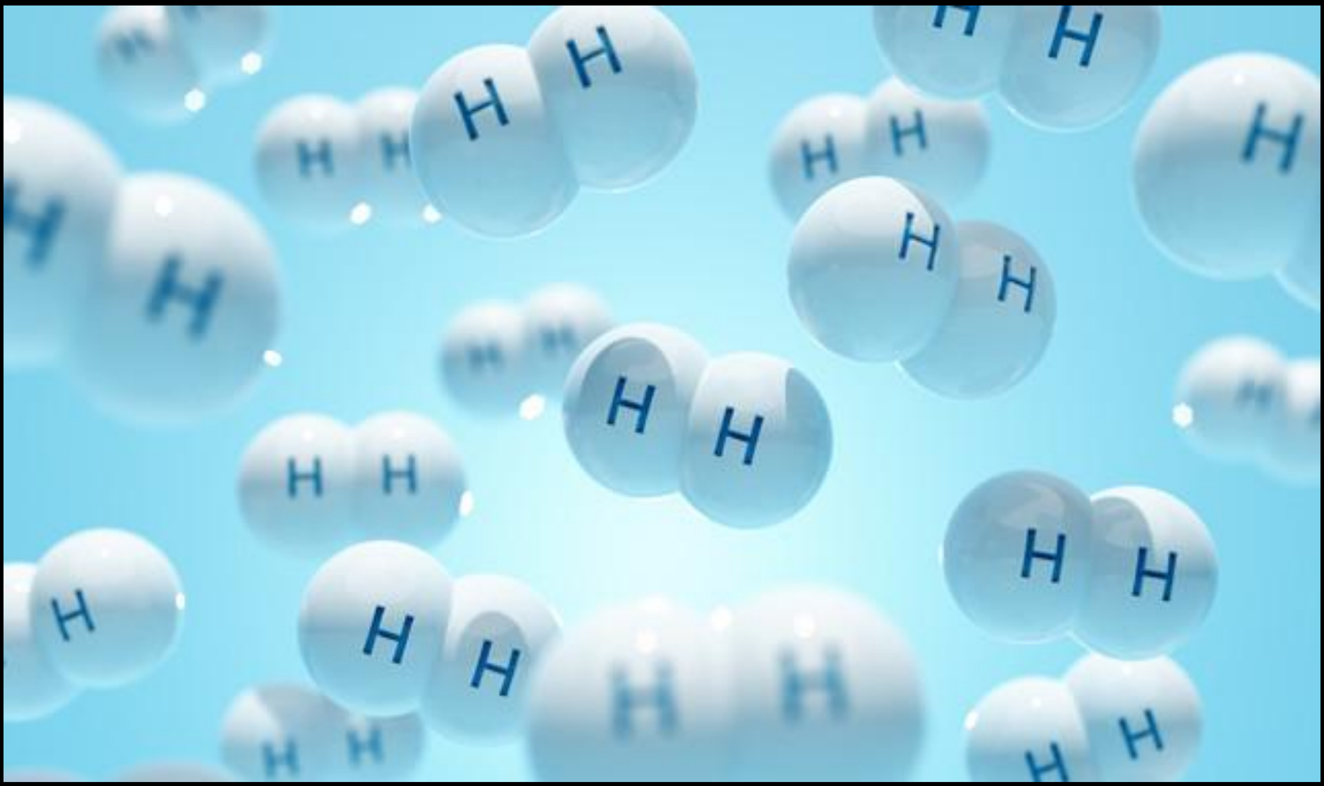

Pathways for Transmission of Hydrogen in Natural Gas Pipelines and City Gas Distribution Network

Final Report

19 June 2025

Submitted by:

ICF Consulting India Pvt. Ltd.

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Table of Contents

Contents

List of Tables

List of Figures

Scope of Work

Broadly, the study was segmented into 5 tasks-

Task	Description
Task 1	*Mapping demand-supply with respect to supply infrastructure*
1.a	Assess the demand for green hydrogen, sector-wise (considering industrial application in oil refining, ammonia for fertilizers, high value chemicals, iron and steel making, industrial process heat, transport, exports etc.) and state-wise, up to 2040 (in five-year intervals)
1.b	With the long term aim of transporting 100% hydrogen through repurposed and dedicated hydrogen pipelines , assess the role of supplying blended hydrogen (in the short and medium term) to consumers that do not require high-purity hydrogen, through the national gas grid of common carrier pipelines
1.c	Assess the state-wise supply potential of green hydrogen, taking into account the technical and realistic potential of renewable energy (RE), installation rates of renewable energy projects, electricity demand (as in many applications, electrification would receive priority access to renewable energy), conversion considerations to green hydrogen (efficiency of electrolyser, full load hours etc.) inter alia.
1.d	Map the demand and supply (as assessed in subtasks 1.a, 1.b and 1.c) with the supply infrastructure i.e. India's national gas grid of common carrier pipelines (existing and planned), highlighting gaps in geographic extent, interconnectivity, hydrogen purity considerations, carrying capacity, maintenance and control structure, safety procedures, grid management, public acceptance inter alia.
Task 2	*Technical Assessment of the Pipeline Sector*
2.a	Map and assess the entire value chain of the pipeline industry to identify constraints/bottlenecks/barriers in either utilization of the existing pipelines for blending or repurposing, as well as for creating new dedicated hydrogen pipelines.
2.b	The assessment, with the aim of gradually creating a dedicated hydrogen infrastructure would be benchmarked at five-year intervals up to 2040 indicating milestones to facilitate a pan-India hydrogen infrastructure thus enabling the supply and export of low carbon hydrogen.
2.c	The analysis would include different end user markets for natural gas (including CGD network) and would enunciate the tolerances for deviation in gas quality/interchangeability in each market, type of existing equipment/process as well as technical requirements of upgrades/conversion of end user equipment in case supply of low carbon hydrogen (with varying blending percentages) is operationalized through the existing infrastructure.
Task 3	*Commercial Assessment of the Pipeline Sector*
3.a	Assess the cost of hydrogen transportation through refurbished pipelines as well as new dedicated pipelines, taking into consideration CAPEX (pipeline, compressor, sensors etc.), OPEX (compressor

	power, pipeline O&M etc.). In addition, assess the cost associated with transport of hydrogen by other means such as road, rail, etc.
3.b	Assess techno-commercially the entire value chain of low carbon hydrogen transportation (benchmarked at five-year intervals up to 2040) through pipelines.
3.c	Based on analysis done in sub-tasks 3.a and 3.b, the consultant would also draw up business models for use of low carbon hydrogen into the gas system (blended or separated) for various end-user segments such as CGD networks, industries, transportation inter alia. The business models would reflect low carbon hydrogen's (delivered through pipelines) cost competitiveness with respect to other available low carbon alternatives.
3.d	The analysis would also establish the cost and commercial feasibility for upgradation/repurposing the existing pipeline or creating new dedicated infrastructure for different hydrogen blending percentages.
Task 4	*Policy and Regulatory Framework*
4.a	Mapping the regulatory structure for promoting low carbon hydrogen markets in selected international jurisdictions such as USA, UK, Australia, inter alia
4.b	Benchmarking the existing technical standards in India with global standards for hydrogen storage, transportation and distribution for repurposed NG infrastructure and providing a summary of regulations introduced internationally to support blending of hydrogen with natural gas in pipelines.
4.c	Reviewing existing PNGRB regulations, identification of gaps in existing regulations (including market, technical and safety) for blending of hydrogen and suggesting required changes. This shall also include safety-related standards.
4.d	Identifying key initiatives and plans across the globe to enable partnerships and policy changes required for establishing a hydrogen economy.
Task 5	*Roadmap for Transmission of Hydrogen Infrastructure (Pipeline)*
5.a	Developing a roadmap till 2040, including goals, gaps and barriers, actionable tasks, associated costs, financing requirements, priorities, and timelines for transmission of hydrogen through the existing as well as new oil and gas pipelines/network.

Executive Summary

Rising average global temperatures, coupled with increasing carbon emissions and mounting incidents of climate related disasters has prompted many countries to seriously explore sustainable energy sources. In India too, several regions have been experiencing alarmingly high wet bulb temperatures approaching dangerous levels.

The Indian economy is going through a rapid growth phase resulting in a massive increase in energy demand. However, to achieve energy security and avert impending climate related disasters, India must reduce its dependence on imported fossil fuel.

Among various sustainable energy sources, green hydrogen has emerged as a promising candidate for large scale adoption. Low carbon hydrogen could be the key to addressing India's energy security and environmental concerns, while simultaneously enabling the country to meet its growing energy demand. Recognizing the significance of the green hydrogen sector, The National Green Hydrogen Mission aims to develop India as a global hub for green hydrogen production and utilization.

While large scale adoption of green hydrogen is desirable, a sudden transition is likely to be costly, disruptive and detrimental to development. Hence, this report explores the integration of green hydrogen into existing natural gas pipelines, to leverage hydrogen's potential, while utilizing existing infrastructure, to facilitate a smooth transition to large scale adoption of green hydrogen.

The Government of India has outlined a detailed ***Hydrogen Mission*** to drive economic growth and reduce carbon emissions in an effort to reach India's goal of **net-zero emissions by 2070.** Achieving NGHM targets and increasing the overall consumption of hydrogen requires infrastructure for storage and transmission of hydrogen. This study evaluates the feasibility of integrating green hydrogen into the existing natural gas transmission infrastructure.

The primary objectives of this study are, to understand the techno-commercial feasibility and limits of hydrogen blending in the natural gas pipeline infrastructure, and to figure out a pathway for developing low carbon hydrogen production, storage and utilization infrastructure in India.

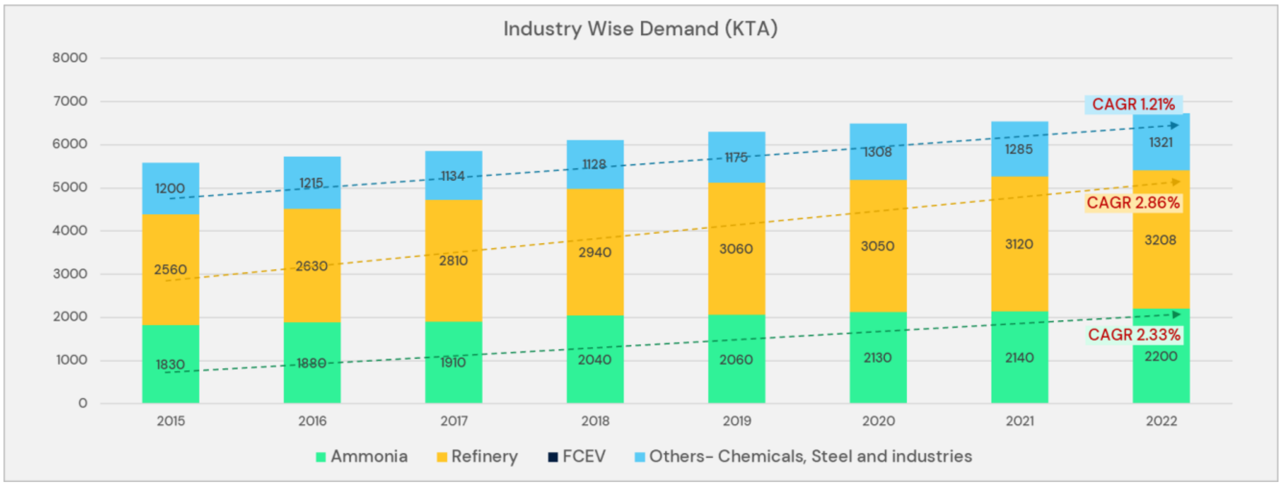
This study answers the following key questions:

- What will drive up the consumption of low carbon hydrogen in India? Where are the key demand centers for low carbon hydrogen?
- What are the safety and efficiency limits for blending low carbon hydrogen with natural gas in existing pipelines? How canH_2 blending be made commercially viable?
- What are the changes required in the current regulatory framework governing gas pipelines to facilitate hydrogen blending with natural gas?
- How can Indian stakeholders and regulators develop infrastructure for either pure or blended hydrogen?

A. Hydrogen Demand and Supply Assessment

India has installed several new refineries, ammonia and chemical plants, which use hydrogen as feedstock, resulting in a growth in the hydrogen demand. The chart below illustrates that hydrogen demand has grown steadily with CAGR of 2.7% from FY 2015- 2022, with the ammonia and refinery sectors contributing to a sizable portion of the overall demand.

Figure 1: Industry-wise hydrogen demand (Historical)



ICF has estimated the future hydrogen demand, using propriety models specific to current and upcoming sectors. The resulting demand forecast is divided into two sections:

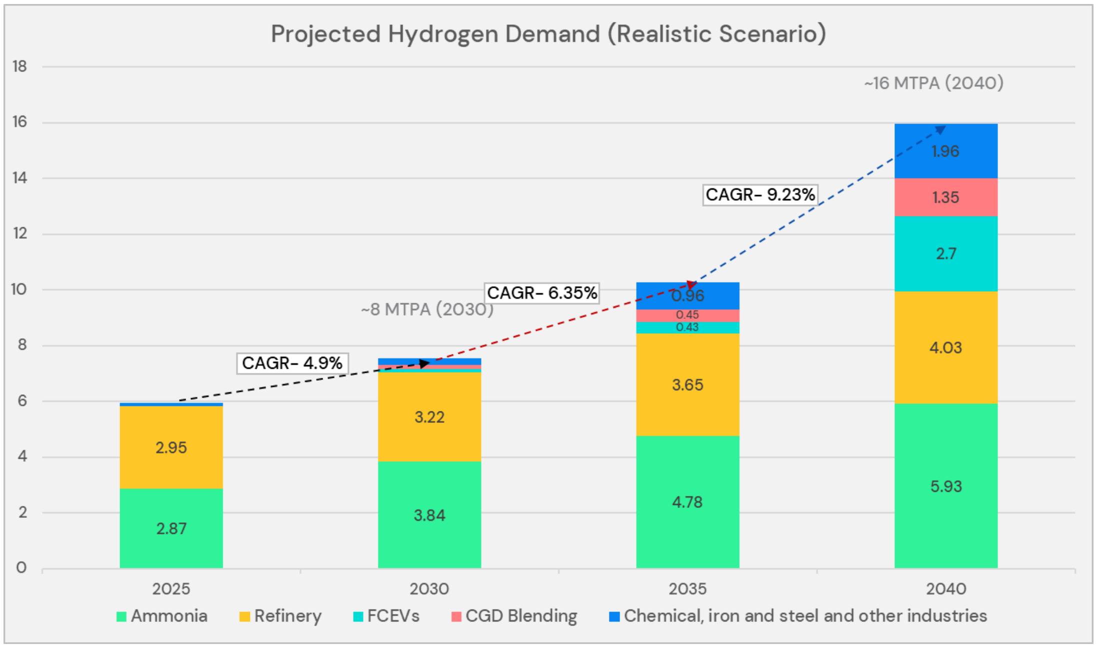
- The refinery and ammonia industries, that are traditional consumers of hydrogen, are likely to continue to drive the hydrogen demand in next decade.
- However, further in the future, hydrogen demand will be driven by upcoming hydrogen applications such as blending in city gas distribution sector, fuel cell electric vehicles (FCEV) and hydrogen based DRI for iron making.

Some of the key insights from our demand projection are as follows:

- The refinery and ammonia sector, propelled by the installation of additional refineries to enable import substitution of ammonia, will drive demand growth over the next decade.
- Upcoming hydrogen applications such as CGD blending, FCEV and hydrogen based DRI will drive demand growth post 2035.

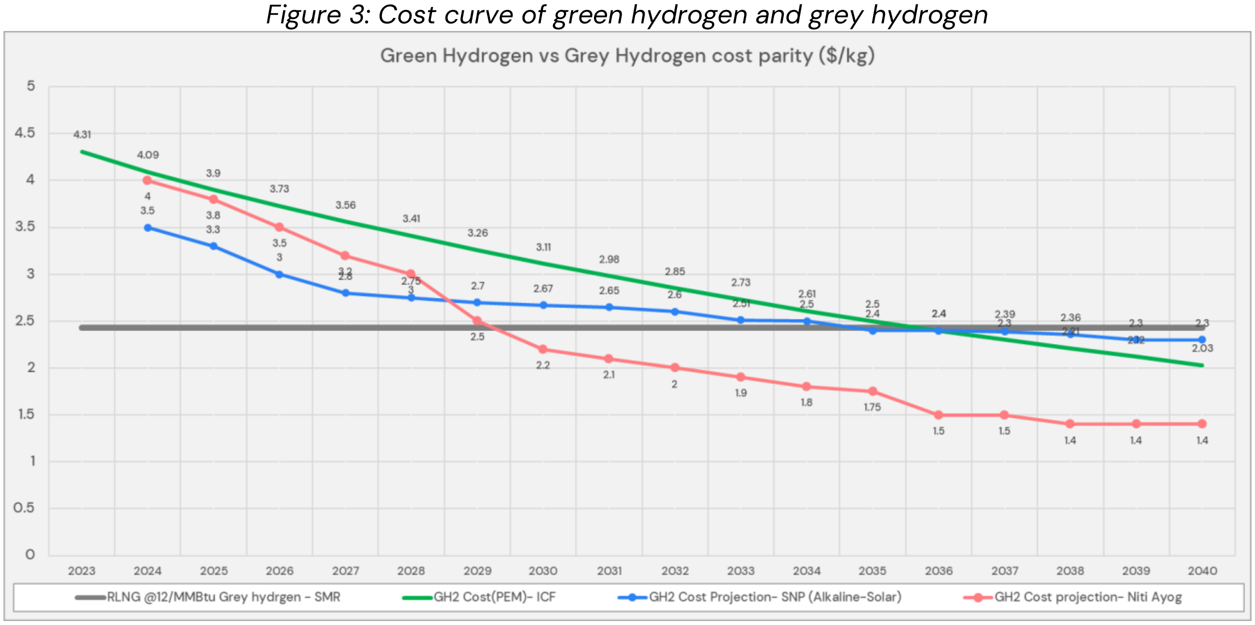
The chart below illustrates that hydrogen demand will increase from the current value of 6.5 MTPA to 8 MTPA by 2030, and nearly double in next ten years (2030-2040) to reach 16 MTPA by 2040

Figure 2: Industry-wise Hydrogen demand (Projection)



The demand for hydrogen will be met by grey hydrogen (through steam methane reforming process) and green hydrogen. Currently, grey hydrogen dominates the hydrogen consumption in India, but green hydrogen will start making its presence felt due to the support offered by the government of India under the NGHM mission. While the increasing demand for hydrogen is expected, the ratio of green to grey hydrogen depends on their cost competitiveness. Currently, green hydrogen is 80% costlier than grey hydrogen. However, we expect that **cost parity will be realized in 2035,** while NITI Aayog expects to achieve cost parity by **2029**. The following figure shows a comparison of estimates by different organizations.

Figure 3: Cost curve of green hydrogen and grey hydrogen

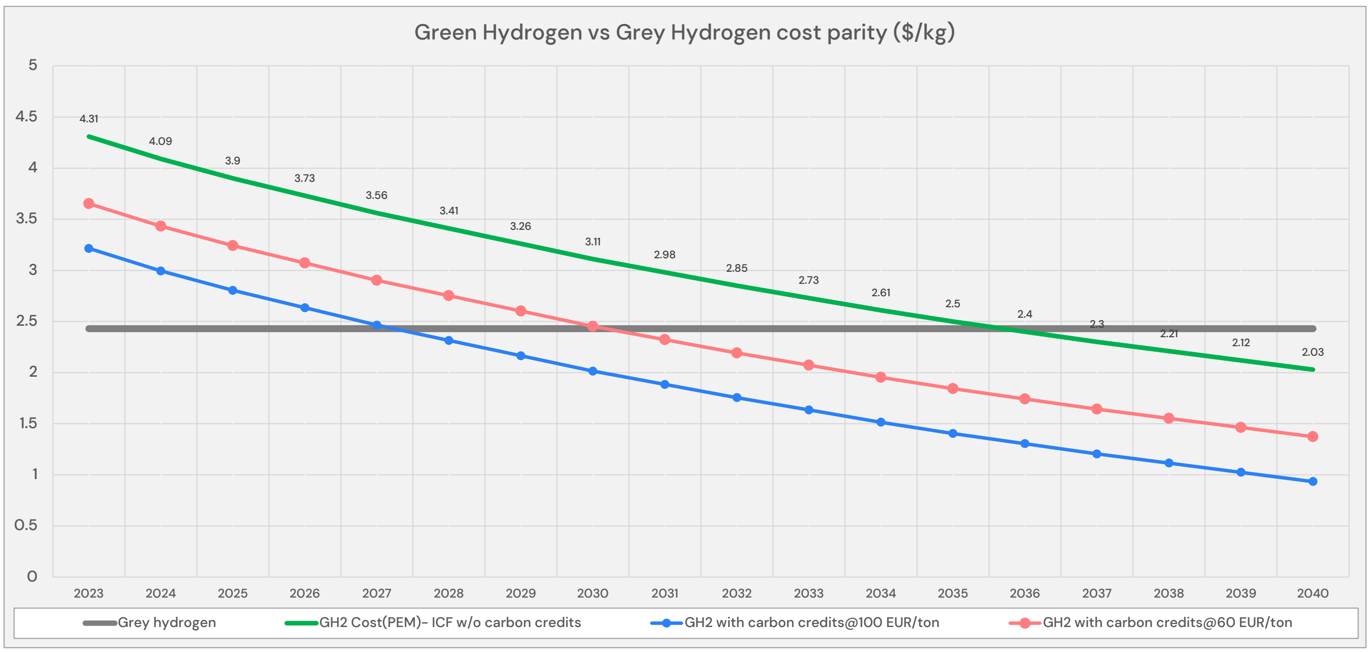


The difference in price curves for green hydrogen are based on different estimates for rate of expected improvement in efficiency of electrolyser, reduction in electrolyser Capex due to economy of scale and reduction in renewable power price.

However, due to policies like carbon **pricing and MNRE incentives** for green hydrogen production (under NGHM scheme), cost parity may be realized earlier, depending on prevalent carbon prices. We have considered two cases for carbon credits, based on implementations of carbon credit policies in Europe in the last year. We evaluated the impact of carbon credits @100 EUR/ton and carbon credits @EUR 60/ton.

The following figure shows that cost parity can be achieved in **2027** with carbon credits @ 100 EUR/ton, and in **2030** with carbon credits @ 60 EUR/ton. Thus, depending on prevailing carbon prices, it is expected that green hydrogen will become cost competitive against grey hydrogen earlier than 2035.

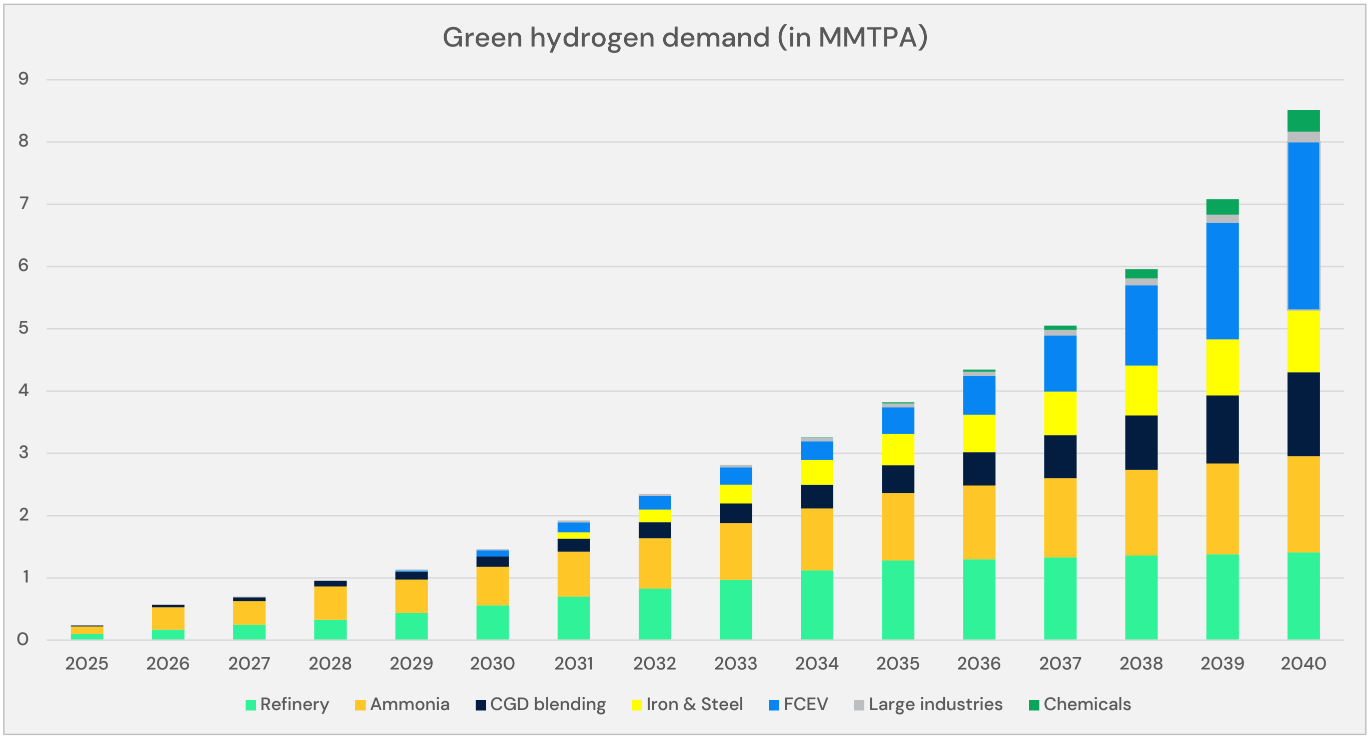
Figure 4: Cost curve of green hydrogen and grey hydrogen with carbon pricing



While cost parity would encourage growth in green hydrogen demand, the initial push for consuming green hydrogen needs to be driven by demand mandates in the refinery and ammonia sectors. We have seen tenders issued for the refinery and ammonia sectors under NGHM SIGHT Scheme – Tranche 2A and 2B to anchor green hydrogen demand.

Based on our models for price parity and mandates, we forecast that green hydrogen may account for ~20% of the total hydrogen demand by 2030 and ~50% by 2040. The chart below illustrates that green hydrogen demand till 2030 will be driven through mandates and government support, but as green hydrogen starts becoming cost competitive against grey hydrogen, new demand applications such as FCEV, hydrogen based DRI and CGD blending will drive demand growth.

Figure 5: Green Hydrogen demand curve



B. Technical and Commercial Assessment

To assess blending limits in the existing natural gas infrastructure, a comprehensive literature review was conducted, encompassing 19 published documents and 17 pilot projects from around the world. In addition to the literature review, consultations were held with stakeholders, including GAIL (India) Limited, Pipeline Infrastructure Limited (PIL), Engineers India Limited (EIL), and Honeywell. These consultations revealed the practical challenges of blending hydrogen in the natural gas pipeline infrastructure.

Key insights from the study:

- On a network-wide level, blending **up to 2% is achievable** with minimal adjustments.
- Blending up to **10% is technically possible but needs case-specific analysis.** A detailed pipeline analysis needs to be undertaken to identify specific limits for individual key pipelines and their associated infrastructure.
- **Blending exceeding 10%** presents a **significant challenge**, requiring substantial system changes.
- Developing pure hydrogen pipelines and supporting infrastructure may be more cost effective than implementing more than 10% blending.

The table below illustrates critical components of the natural gas pipeline infrastructure with their blending limits. Some of the key observations are:

- Helium cylinders in process gas chromatographs need to be replaced with argon cylinders. This will be an operational expense, and not require any significant capital investment.
- CNG vehicle tanks have a limit of 2% hydrogen blending in natural gas by volume. Thus, any blending above 2% would require deblending solutions close to CNG stations, resulting in an additional capex of INR 5.2 Cr per CNG station.
- Similarly in fertilizer plants (urea plants), more than 2% blending of hydrogen in natural gas lowers the efficiency of the urea plant, so an onsite deblending kit is required. There deblending costs and additional INR 3.2/kg of Urea.
- Other critical equipment such as gas compressors, turbines etc. require modifications resulting in between 10%-15% of additional capital expenditure, depending on make and model of the equipment.

Table 1: Technical Assessment Summary

S.NO.	Element	Blending Limit (without modifications)	Blending Limit (with modifications)	Key Remarks/Retro fitment Solution
1	Compressor	2%-5%	15%-20%	Swapping gas turbines or internal combustion engines with electric motors
2	Electrically Driven Compressor	15%-20%	-	-
3	Valve	10%	-	Required new equipment
4	Gas Filter	10%		Required new equipment
5	Fuel Filter	10%		Required new equipment
6	Odorant	15%	-	
7	Insulation Joint	10%-20%	-	
8	Volumetric Meters	10%		Required new equipment
9	Process gas chromatograph	<=0.2%	10%-20%	Replace helium cylinders with Argon Cylinder
10	Gas Meters	10% - 50%		
11	Gas Turbine	1%-2%	15%-20%	Modifications to increase limit to 15% - 20%
12	Feedstock/Reformer	2%	-	Lower efficiency. Requires deblending solution
13	Burner/Gas Stove	10%	20%-100%	
14	CNG Vehicle fuel Tank	2%		Requires deblending solution
15	Domestic Appliances	20%		
16	Transmission pipeline (Steel)	5%-10%	-	Requires changes in the operating pressure. Needs to be evaluated for specific pipeline with their P&ID diagrams
17	Distribution pipeline (PE)	25%-100%	-	
18	Condensing and Steam Boilers	5%-10%	20%-100%	

This commercial study evaluates the cost implications of repurposing existing natural gas pipeline infrastructure for hydrogen blending at various concentration levels, specifically 0% to 2%, 2% to 5%, 5% to 10%, and 10% to 20%. It identifies specific components within the natural gas infrastructure that require replacement at each blending threshold, detailing retro fitment solutions and estimating the associated increase in capital expenditure. The table below presents these retro fitment solutions and the anticipated capital expenditure.

Table 2: Commercial Assessment Summary

S.NO.	Element	Blending Limit (without modifications)	Retro fitment solution	Additional cost
1	Compressor (Gas Driven)	2%-5%	Possible solution for retrofit of compressor is replacing gas/IC engine drive with electrical drive.	6.5%-11% of Capex
2	Compressor (Electrically Driven)	15%-20%	Requires replacement	
3	Valve	10%	Requires replacement	
4	Gas Filter	10%	Requires replacement	
5	Fuel Filter	10%	Requires replacement	
6	Odorizer	15%	Requires replacement	
7	Insulation Joint	10%-20%		
8	Volumetric Meters	10%	Requires replacement	
9	Process gas chromatograph	<=0.2%	Replace helium cylinders with argon cylinders.	500 USD/Year/PGC
10	Gas Meters	10% - 50%		
11	Gas Turbine	1%-2%		10% of Capex
12	Feedstock/Reformer	2%	Deblending	INR 3.2/kg of Urea
13	Burner/Gas Stove	10%		
14	CNG Vehicle fuel Tank	2%	Deblending	5.2 Cr/CNG station
15	Condensing and Steam Boilers	5%-10%	Majority of cost increase coming from a burner suitable to fire hydrogen that produces low NOx emissions	35%-40% of Capex

C. Regulatory Assessment

We chose regulations implemented in USA, UK and Australia as a benchmark for identifying the gaps where India does not currently have regulations. Through this study, we were able to assess areas where entirely new regulations, or modifications to present regulations, are required.

The table below illustrates key areas where regulations regarding hydrogen policy need to be developed. Some of the key insights are:

- India is one of the leading nations to define standards for green hydrogen, although it is limited to hydrogen production from electrolysis and biomass.
- Hydrogen transport through pipelines needs comprehensive regulations and a defined nodal agency. Current transportation of natural gas and petroleum products through pipelines is under the purview of PNGRB. The current scope of the PNGRB Act does not include hydrogen (either as pure hydrogen or blended with natural gas) but amendments are underway to include hydrogen under the PNGRB Act.
- PNGRB formulates safety regulations for natural gas networks. These regulations may require a significant overhaul to include hydrogen.
- PNGRB would also need to develop regulations for blending hydrogen in natural gas networks, including blending limits, standard operating procedures for applying for hydrogen blending and approval mechanisms to support hydrogen blending

Table 3: Regulatory Assessment

	REGULATIONS	INDIA	USA	UK	AUS	IDENTIFIED GAPS
1. Production	Explosive / Hazardous Good Management	✅	❌	✅	✅	★Clean Hydrogen Production Standard defined for hydrogen from electrolysis and biomass
	Environment Related Regulations and/or Regulations on Emissions	✅	✅	✅	✅	
	Clean Hydrogen Production Standard	★	✅	❌	❌	
	Explosive/ Hazardous substance management in Workplace/Accident Prev	✅	❌	✅	✅	
	Waste Disposal	✅	❌	❌	✅	
	Regulations for manufacturers of industrial chemicals	✅	❌	❌	✅	
2. Storage	Regulations for designing storage vessel	✅	❌	❌	❌	× Environment and related regulations
	Regulations for granting storage permissions/licenses for hydrogen	✅	✅	✅	❌	
	Safety regulations for storage at work	✅	✅	✅	❌	
	Control of operations of storage facility	✅	❌	✅	❌	
	Environment and related regulations	❌	❌	✅	❌	
3. Transportation	Rules for control/Risk Assessment over transportation of explosives	✅	✅	✅	❌	★Transportation via Pipelines is regulated by PNGRB. Current scope of PNGRB does not include Hydrogen but amendments are underway to include H_2 under the Act.
	Transportation via Gas Cylinders	✅	❌	❌	❌	
	Transportation via Pipelines	❌	✅	✅	✅	

	Transportation via Road	✅	✅	✅	✅	★ In India, PNGRB regulates Safety plan for Gas Networks. However, inclusion of hydrogen under its purview is not done yet. × Transportation via Waterways Hydrogen blending guidelines. GSR to be amended for hydrogen dispensing
	Transportation via Rail	✅	✅	✅	✅	
	Transportation via Inland Waterways	❌	✅	✅	✅	
	Safety plan for Gas Networks	★	❌	✅	✅	
	Import Regulations	✅	✅	❌	❌	
	Hydrogen blending guidelines	❌	❌	✅	❌	
4. End Usage	Electricity Generation	❌	✅	❌	✅	Regulations on chemical and industrial use not clear Regulations for Electricity Production
	Export-Import	✅	✅	❌	✅	
	Chemical and Industrial Use	★	✅	✅	✅	
	Transport Use	✅	✅	✅	✅	

Successfully blending hydrogen in the natural gas pipeline network requires a regulator **to be ready to regulate either a blended or a pure hydrogen pipeline**. PNGRB, the only body regulating energy pipelines in India, is well suited to regulate pipelines for hydrogen blended with natural gas as well as pure hydrogen.

- PNGRB is already a regulator for gas pipelines, so they are well suited to regulate hydrogen pipelines.
- Current PNGRB regulations may be modified to support H2 only pipelines.
- The economic and technical principles of H2 are similar to gas, which PNGRB already specializes in distributing.
- Like CGD, there could also be hydrogen distribution licenses near anchor demand centers. PNGRB is fit to oversee them all.

For all these reasons, PNGRB is best suited for the role of a regulator for hydrogen distribution either as pure hydrogen or blended with natural gas.

To empower the PNGRB to regulate the storage and transportation of hydrogen gas, the PNGRB Act, 2006 needs to be amended.

Table 4: Amendments to the PNGRB Act

S.No	Section of the Act	Recommendation
1	Section 11 - Functions of the Board	It is recommended that blending of hydrogen in natural gas is expressly included in this section as part of the functions of the board
2	Section 2 - Definitions	It is recommended that natural gas blends (with hydrogen) be notified under this section

		Given the fact that all regulations stemming from the Act, utilize the term "Natural Gas", it is proposed that the definition of Natural Gas be expanded to include "Blended Natural Gas" and/or "Pure Hydrogen" within the umbrella term of "Natural Gas". It is also suggested to have a separate definition for blended natural gas.
3	Section 14: Register	It is suggested that Section 14 of the PNGRB Act be amended to explicitly incorporate hydrogen-related activities within the scope of the Petroleum and Natural Gas Register. Specifically, subparagraph (a) should include entities engaged in marketing hydrogen and establishing and operating hydrogen related infrastructure including storage infrastructure.
5	Section 17: Application for Authorisation	Modify existing clauses (1) and (2): Include "or hydrogen" after "natural gas" to explicitly encompass hydrogen blending within the purview of authorization requirements for both common/contract carrier pipelines and city/local distribution networks.
6	Section 61: Power of the Board to make Regulations	Additions to be made in order to empower the board to make regulations and include hydrogen in its purview: •Technical specifications and safety protocols for hydrogen storage and blending infrastructure. •Blending ratios and quality standards for hydrogen-natural gas mixtures. •Monitoring and reporting requirements for hydrogen blending operations. •Certification and accreditation frameworks for relevant entities and equipment. •Economic and financial incentives to promote hydrogen blending projects. •Any other matter necessary for the effective implementation of hydrogen blending in India.

A detailed examination of the different regulations that require amendments has been discussed in section 6.5 of this report.

D. Roadmap for developing hydrogen infrastructure in India

The conclusions of the Technical, Commercial and Regulatory assessments have enabled the creation of a roadmap to realize the NGHM's vision.

The key action areas for hydrogen blending in the short, medium and long term include the following: -

Figure 6: Roadmap

Short term: 2024-2025

- Technical assessment of the existing pipeline and CGD networks and materials
- Physical testing at a test site in India
- Testing of different percentage blends of hydrogen with natural gas
- Modification of PNGRB Act, and regulatory changes

Medium term: 2025-2030

- Retrofit pipeline infrastructure including deblending solutions for CNG stations and monitor progress
- Modification of key regulations to allow for hydrogen /hydrogen blended NG through pipeline.
- Modification of safety standard for hydrogen to be used after blending
- Develop business models or hydrogen blending and use stakeholder consultations, government funding schemes like SIGHT Programme and VGF Scheme

Long term: 2030-2040

- Roll out hydrogen blending at safe limits pan India (maximum 20% blending)
- Develop of new pipelines that are compatible with higher hydrogen limits
- Dedicated hydrogen pipelines that may be used for local/hub-based delivery of hydrogen

We identified key activities that PNGRB should focus on over the next 12 months to support hydrogen blending in natural gas pipelines:

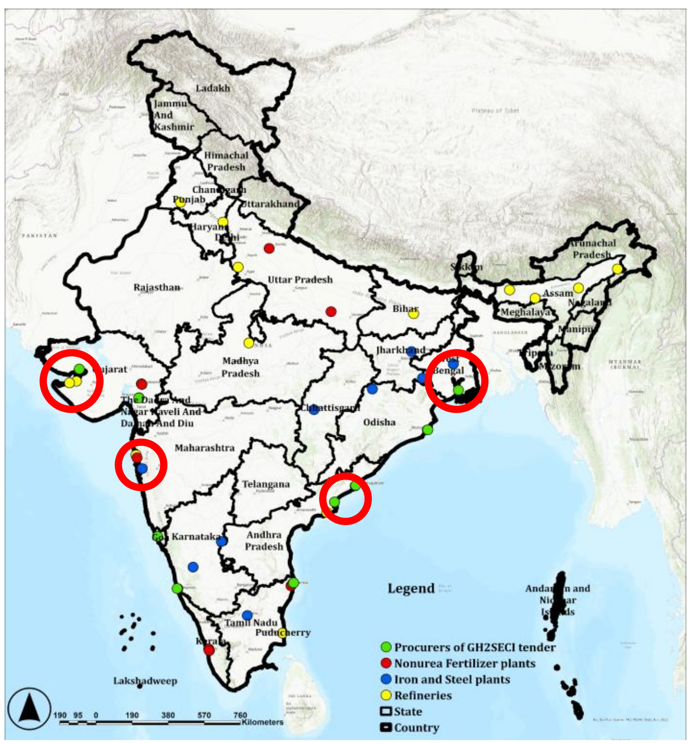
- Modification of PNGRB Act to allow PNGRB to regulate hydrogen blended natural gas/pure hydrogen pipeline and storage infrastructure.
- Conduct detailed technical assessments for the major pipelines and CGD networks. The detailed technical assessment would include a review of P&ID information for the equipment, pipeline network etc. to identify blending limits for each pipeline.
- PNGRB board may visit the UK and hold bilateral meetings with (1) National Grid Transco (2) OFGEM (3) DESNZ (4) SGN (gas distribution company); and conduct site visits to (a) HyDeploy project (b) Spadeadam facility to witness the testing being done for hydrogen blending in transmission and distribution systems.
- Work with PESO to formulate technical standards and regulations for hydrogen storage and dispensation.
- Conduct physical testing at a test site in India, with different percentage blends (5%, 10%, 20%), simulating actual gas flow conditions by installing small pipeline and CGD network sections with the materials to be used in the real gas network as identified in the technical study above.
- Test different percentage blends of hydrogen with natural gas under varying temperature and pressure conditions to simulate multi-year operations.
- Develop safety norms to accommodate different percentages of blending.

- Run pilot programs for different percentages of hydrogen blending in the natural gas pipeline network.

While long distance transnational natural gas pipelines may be used to distribute blended hydrogen, applications such as refineries, non-urea fertilizer plants, chemical and iron and steel plants require pure hydrogen. Thus, we have identified the key states with large refineries, non-urea fertilizer plants and iron and steel plants as promising locations for hydrogen hubs, to develop pure hydrogen pipelines. Pure hydrogen pipelines can be established in the states of *Maharashtra, Tamil Nadu, Andhra Pradesh, West Bengal, Gujarat, and Kerala*. Refineries, fertilizer plants and iron & steel plants across the country have been mapped, to figure out locations where demand for green hydrogen will be the maximum.

The chart below shows potential states suitable for developing pure hydrogen pipelines based on current SECI tenders under 2A SIGHT scheme and anchor customers for pure hydrogen.

Figure 7: Demand clusters for Hydrogen



PNGRB, apart from developing a hydrogen blending roadmap, should also regulate pure hydrogen pipelines.

The key action areas for implementation of pure hydrogen pipelines include the following: -

- Modification of PNGRB Act to allow PNGRB to regulate pure hydrogen pipelines and storage infrastructure.

- New regulations governing various aspects of pure hydrogen networks, including authorization to develop a hydrogen distribution network, capacity determination, tariff determination, formulation of technical standards and safety regulations
- Demand assessment of hydrogen for industrial and chemical purposes near identified hubs
- Development of business models to ensure capex recovery and promotion of usage of green hydrogen in the local network.

This study serves as a starting point for understanding the potential of India's hydrogen economy. To move forward, we need to conduct detailed studies, test new technologies, and carry out pilot projects. By doing this, we can create the necessary infrastructure, policies, and investments to make green hydrogen a widely used, sustainable and commercially viable alternative to imported fossil fuels.

Introduction

The growing urgency to neutralize and reverse climate change requires a rapid adoption of green fuels to satisfy energy demands. This has been well recognized in various COPs and many countries, including India have planned timelines to achieve net-zero emissions. As per the United Nations report, more than 70 countries, including the biggest economies like China, the United States, and the European Union, which account for 76% of global emissions, have set their net-zero targets.

One way to achieve net-zero is through widespread adoption of low carbon hydrogen (green hydrogen, blue hydrogen, pink hydrogen, turquoise etc.). Recognizing this possibility, the Government of India (GOI) on February 17, 2022, launched India's Green Hydrogen Policy. The policy discussed various grid-based incentives to ensure cheaper renewable power to generate green hydrogen. The GOI, furthered its Green Hydrogen Road map, by launching the Green Hydrogen Mission dated January 4, 2023. **The Mission targets a production of 5 MMT of green Hydrogen per annum by 2030 and aims to install 60-100 GW electrolyser capacity and 125 GW RE capacity**. Achieving this target will likely **reduce CO2 emissions by 50 MMT**, create **6 lakh new jobs** and attract **investments of around INR 8 lakh crore**.

Availability of supporting infrastructure is essential to achieve the set targets, and to increase the overall consumption of hydrogen. This includes efficient, safe and commercially viable storage and transportation options for hydrogen. Transportation of highly volatile hydrogen requires special safety measures. At present, there are close to 4,500 km of dedicated hydrogen pipelines spread across USA (mainly), Australia, and UK. Besides, pilot projects have also been undertaken to refurbish existing natural gas pipelines and possibly blend hydrogen with natural gas in the existing natural gas network.

In this context, The **Petroleum and Natural Gas Regulatory Board (PNGRB)** is exploring the possibility of blending low carbon hydrogen in existing and up-coming natural gas infrastructure across the country to increase the availability of clean energy. A combination of repurposing the existing Natural Gas (NG) pipelines, along with creating new infrastructure, if required, can provide the requisite boost to a Made-in-India low carbon hydrogen value chain, which aligns with the vision of the Government of India. This approach would improve the utilization of existing trunk pipelines, aggregate hydrogen supply from low carbon hydrogen producers, familiarize consumers with operating conditions of a new fuel, and prepare consumers (domestic, commercial, and industrial) to utilize blended hydrogen (to serve end users that would use) before a probable transition to 100% hydrogen.

Objectives of the study

ICF understands that this study explores the potential of initially blending a small percentage of hydrogen in India's natural gas infrastructure, progressively increasing this percentage and finally moving towards hydrogen only pipelines (retrofit or new).The study is designed to answer the following key questions –

1. What will be the demand for hydrogen, especially green hydrogen, in India over the next few years?
2. What are the supply sources and options for large scale green hydrogen production?
3. How to blend hydrogen in existing natural gas infrastructure in India and what impact (technological and economic) will it have on end users?
4. What changes, in existing gas sector regulations, will be needed to support the blending of hydrogen with natural gas?
5. What are the key technical and safety regulations that must be followed (as per global best practices) to enable smooth and safe blending of hydrogen with natural gas?
6. What roadmap should India follow to progress from initial limited blending to higher blending, and finally

hydrogen only pipelines in the long term.

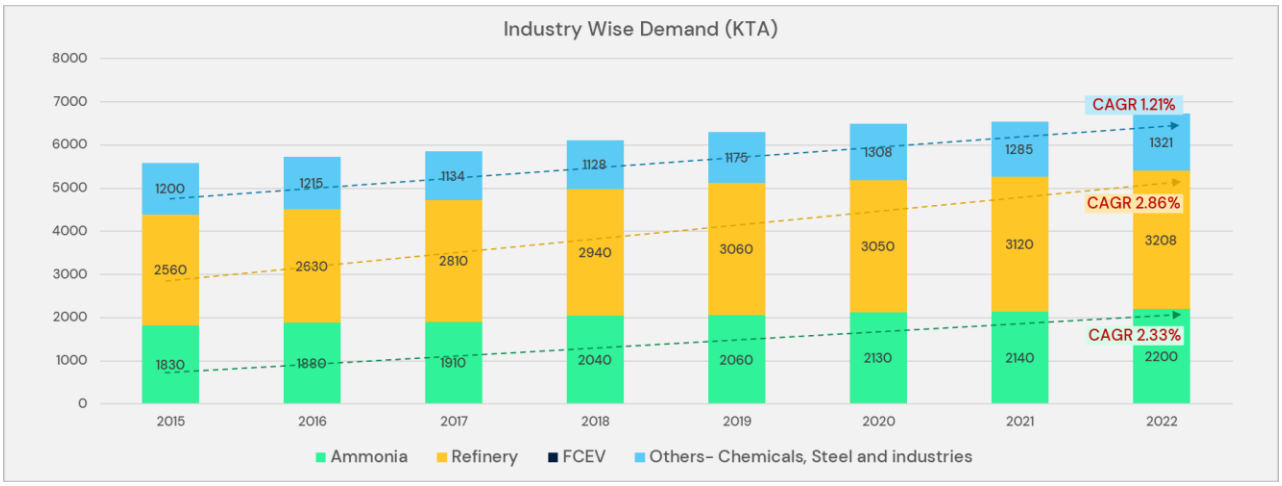
1. Assessment of Hydrogen Demand in India

1.1 Current Hydrogen Demand Scenario

The current hydrogen demand in India is **~6.7 MTPA** as of **FY 2022**. The demand has been growing steadily, with a **CAGR of 2.7% from FY 2015 to FY 2022**(ICF's analysis from primary data). It is evident that hydrogen production has increased every year since 2015, indicating a gradual and steady growth rate. The trend suggests that hydrogen production is likely to continue to grow in the coming years, as the world transitions towards more sustainable energy sources.

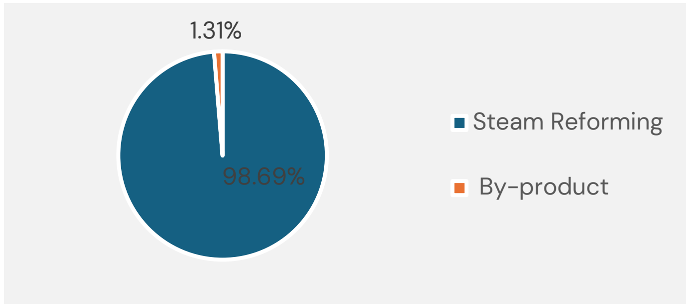
The growth in hydrogen demand is mainly driven by the expanding fertilizer and ammonia sector, as well as refineries. However, to meet the demand of the fertilizer sector, 2235 KTA of ammonia has was imported in 2022. The following chart summarizes the trends in hydrogen production and demand from FY 2015 to FY 2022.

Figure 8:Hydrogen demand in India, FY-2015-2022



Approx. **90% of the hydrogen demand is from captive consumers**, which primarily includes the **fertilizer, refinery, and chemical industries**, while the remaining 10% is merchant demand. Thus, a significant amount (~90%) of hydrogen is being consumed by industries for their own use, with a small amount of hydrogen sold in the market. Moreover, it is worth noting that around 98% hydrogen production facilities in India currently rely on the steam methane reforming (SMR) of natural gas.

Figure 9: Production of Different Types of Hydrogen in India (%)



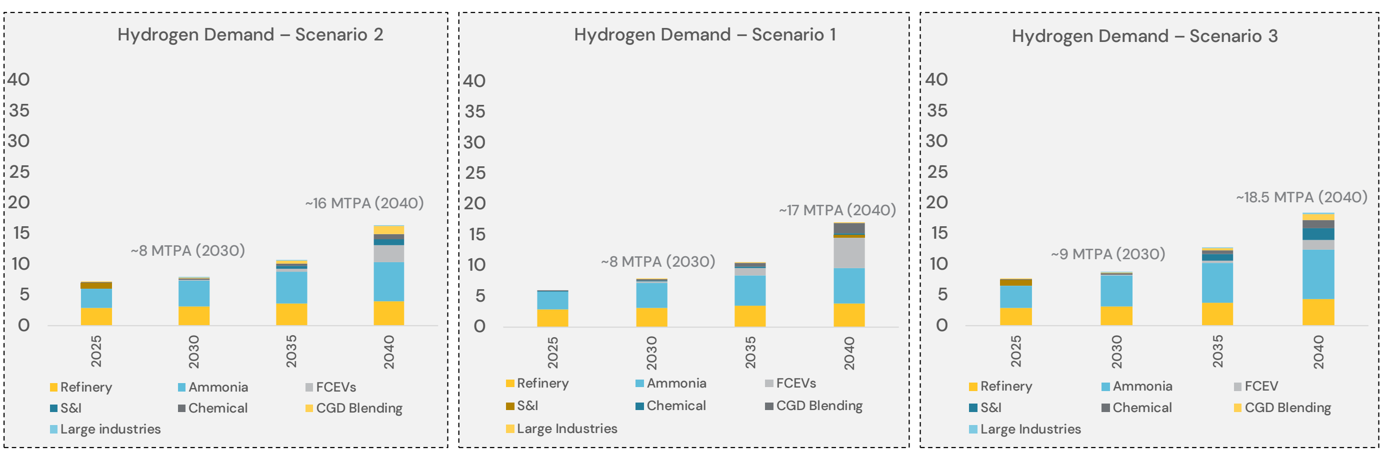
Hydrogen can be utilized in two major ways: Firstly, as a feedstock where it is directly employed in various processes such as refineries, industrial processes and ammonia production. Secondly, as a fuel, hydrogen can be employed to replace other traditional fuels such as diesel through FCEVs, blending with natural gas for CGD etc. Thus, the demand for hydrogen is forecasted across six use cases – i) Refinery ii) Ammonia iii) CGD blending iv) Transport sector (FCEVs) v) Chemicals (Methanol & Hydrogen per oxide) vi) Iron & Steel

We forecast the demand for hydrogen under three scenarios: Conservative, Realistic and Optimistic. As refinery sector demand is inversely proportional to FCEV and CNG demand, conservative of refinery case will be optimistic for FCEV and CNG and vice versa. The table below illustrates the conservative, realistic and optimistic cases and the relationship between these three cases in the identified sectors.

Summary case	Refinery	FCEV	CNG	Ammonia	Iron and Steel	Industries	Chemicals
Scenario 1	Conservative	Optimistic	Optimistic	Conservative	Conservative	Conservative	Conservative
Scenario 2	Realistic	Realistic	Realistic	Realistic	Realistic	Realistic	Realistic
Scenario 3	Optimistic	Conservative	Conservative	Optimistic	Optimistic	Optimistic	Optimistic

A snapshot of **expected hydrogen demand** is shown below:

Figure 10: Hydrogen demand projections 2025-2040



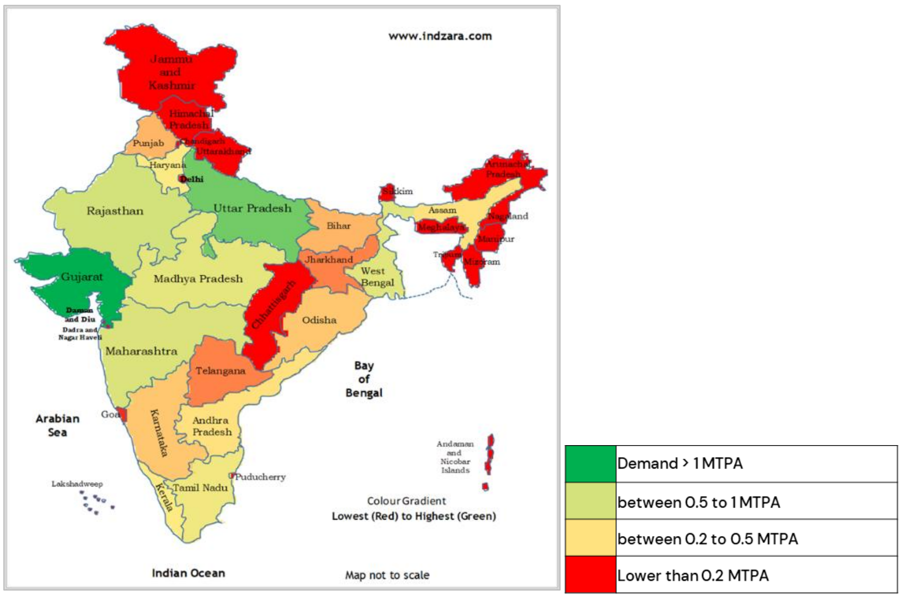
Key insights from the demand projections are as follows:

1. The Hydrogen demand is likely to be between **~8 MTPA and ~9 MTPA** in 2030 and between **~16 MTPA and 19 MTPA** in 2040. There is no significant difference in demand between scenario 2 (Realistic case) or other scenarios as increase in FCEV and CNG demand would offset demand from refineries (due to

low refinery demand) and vice versa.
2. Demand is expected to grow at a rate of **5.3% per year,** to reach 15 MTPA by 2040.
3. Refinery & Ammonia are the key sectors; each having at least a ~**40%** share in the H2 demand till 2030.
4. In 2040, Iron & steel, FCEVs & CGD will be key demand drivers; sharing **~6%, ~16% & ~8%** respectively, of the total demand. (Scenario -2)

Further, a broad state-wise distribution of hydrogen demand is represented in the following heatmap:

Figure 11: Heat map of hydrogen demand across India for the snapshot year 2030



Potential for green hydrogen

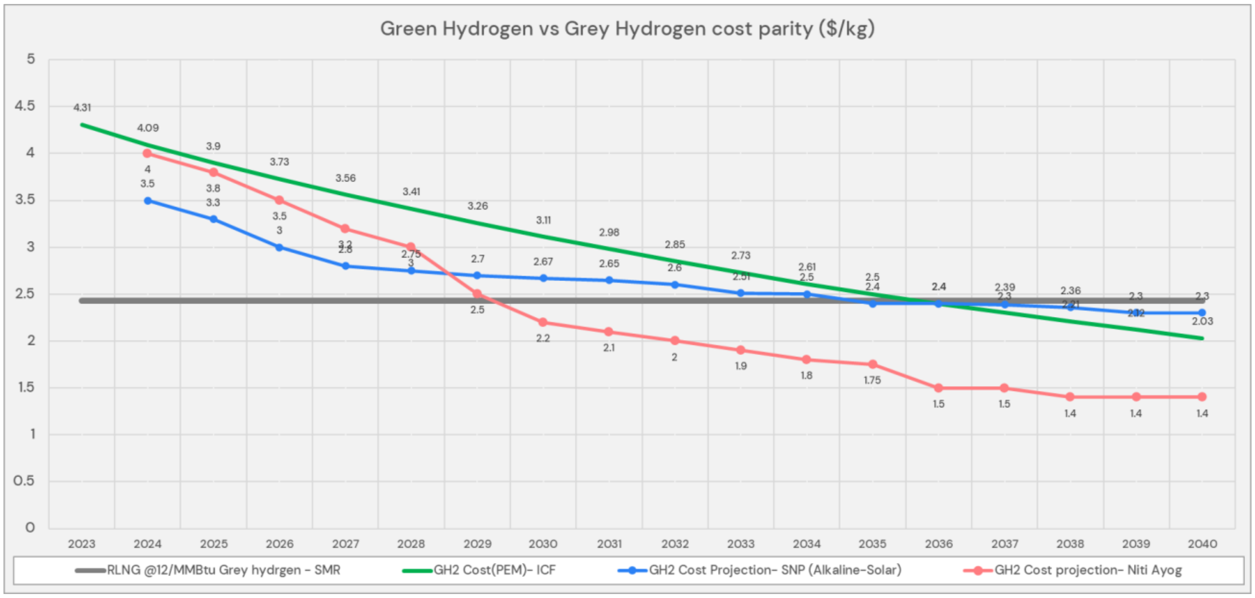
We have forecasted the potential for green hydrogen based on:

- Cost economics of green hydrogen against grey hydrogen
- Cost economic of blending green hydrogen in natural gas infrastructure
- Government policy such as Green Hydrogen Consumption Obligation (GHCO) issued in the draft report.
- Exports requirements such as ammonia export as well as export of green steel to Europe

Cost economics of grey vs green hydrogen

In India, as mentioned above, majority of the hydrogen is produced from Steam Methane Reforming (SMR) process, and thus it is grey hydrogen. Green hydrogen is gaining momentum with encouraging government policy and financial support. The chart below compares the cost of grey hydrogen (from SMR) against the green hydrogen produced through PEM and Alkaline technologies.

Figure 12: Cost comparison between grey and green hydrogen with RLNG @12/MMBtu

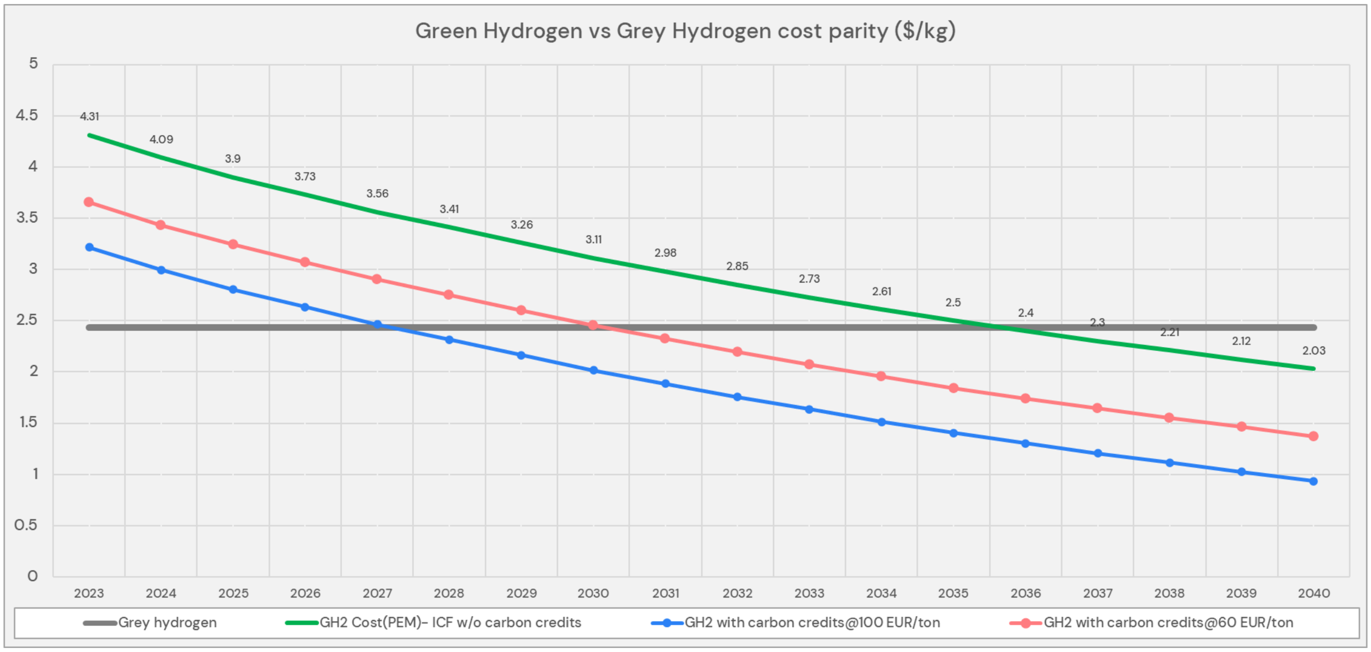


Based on the ICF cost model, green hydrogen will achieve cost parity with grey hydrogen by **2035**, assuming no financial support from the government or carbon pricing.

While green hydrogen may not be cost effective until the early 2030s, measures such as carbon pricing and MNRE incentives will reduce the comparative cost of green hydrogen.
The cost gap can be met by MNRE incentives of Rs. 30-50/kg.

- The scheme offers a **direct subsidy over three years** from the beginning of production and supply, with the following rates-
    - Rs 50/kg of green hydrogen in the first year
    - Rs 40/kg in the second year
    - Rs 30/kg during the third year

Moreover, a cost comparison of green and grey hydrogen, considering carbon credits @ 100 EUR/ton, and 60 EUR/ton was performed. Our findings suggest that by 2027, green hydrogen will be cost competitive with grey hydrogen (assuming carbon credits @ 100 EUR/ton).

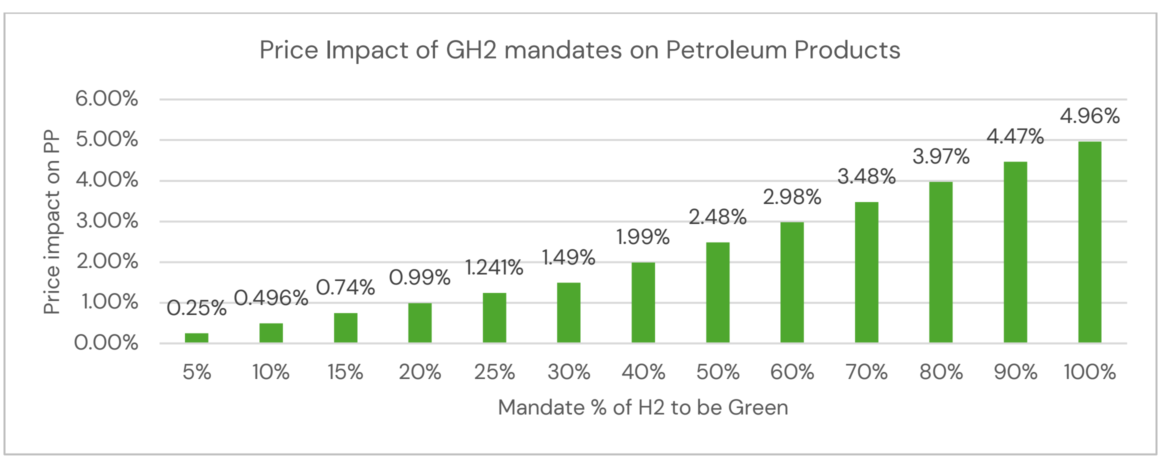


Government policy measures such as mandate for refineries and ammonia

Implementation of mandates in refineries:

In the relentless pursuit of clean energy solutions, governments worldwide are exploring various strategies to reduce reliance on fossil fuels. One approach gaining traction is the implementation of mandates for using green hydrogen in refineries. Green hydrogen, produced from renewable electricity and water, offers the possibility of a clean fuel. However, concerns remain regarding the potential impact of such mandates on consumer costs. This study investigates the economic impact of government mandates requiring refineries to utilize green hydrogen. The study examines a range of GH_2 mandates, from **5%** to **100%**. Our findings, illustrated in the accompanying graph, reveal a surprisingly negligible effect on the final prices of petroleum products, even for a **50%** percent green hydrogen blending mandate. This suggests that green hydrogen mandates may be a viable policy option for promoting clean energy with no significant cost to consumers.

Figure 13: Price impact of Mandates in refineries.



This study analyzes the cost impact of green hydrogen mandates on refineries by simulating the replacement of grey hydrogen with green hydrogen. First, we determine the baseline natural gas volume required by the refinery to achieve its 1 MTPA capacity. Based on the natural gas consumption, we calculate the amount of grey hydrogen generated. We simulate the replacement of a mandated percentage of grey hydrogen with green hydrogen. The cost of this green hydrogen is factored in. To conclude, we assess the overall impact on the refinery's product costs by considering the proportional costs and quantities of crude oil, natural gas, grey hydrogen, and green hydrogen.

Key Assumptions:

Table 5: Key assumptions for green hydrogen mandates in refineries

Price of NG	12 US $/MMBTU
Price of Green Hydrogen	INR 380 / kg
Price of crude	80 $/BBl
1 MMT to refining, hydrogen required	9000 tonnes

Implementation of Blending mandates

If mandates are enforced to blend green hydrogen into natural gas pipelines, the price of RLNG will increase from 15.02 $/mmbtu to 15.57 $/mmbtu in the case of **5% blending (3.66% increase)**, and the price will increase to 15.23 $/mmbtu in the case of **2% blending (1.43% increase).**

Figure 14: Price impact of blending mandates.

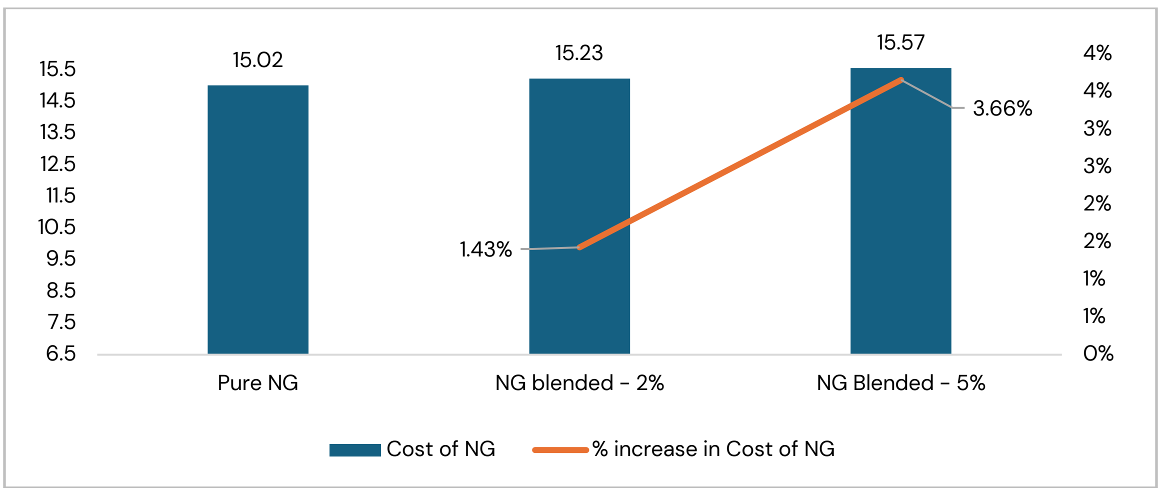


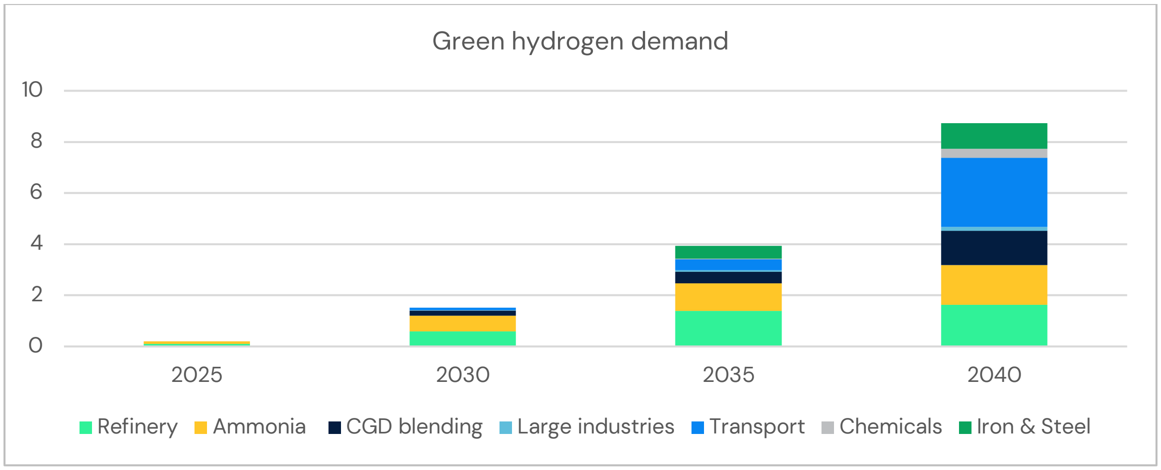
Table 6: Price Impact of H2 blending n Natural Gas

H2 Blending %(by Vol)	RLNG Price ($/mmbtu)	Green H2 Price ($/mmbtu)	Price of NG blended in H2 ($/mmbtu)	% Increase in Price
5% Blending	15.02	56.2	15.57	3.66%
2% Blending	15.02	56.2	15.23	1.43%

Green hydrogen demand

Based on sectoral analysis, out of total hydrogen demand of 13 MTPA by 2040, green hydrogen may account for 8.5 MTPA of a total hydrogen demand of 16 MTPA by 2040. The figure below shows the demand of green hydrogen across key sectors.

Figure 15: Demand of green hydrogen in MTPA across key sectors



2. Green hydrogen production potential

The key resources required for an electrolysis based green hydrogen plant are water & renewable electricity.

Water Availability

The production of green hydrogen via electrolysis involves drawing water from various sources, such as rivers and lakes. This water is then subjected to a reverse osmosis and de-ionization, and subsequently fed into an electrolyser to generate hydrogen. Ideally, a minimum of **9 kg of water is required to produce 1 kg** of hydrogen, but the actual water consumption can range from **59 to 95 kg**[1] **per kg of hydrogen**, after accounting for the demineralization and cooling processes.

Thus, producing 16 MTPA of green hydrogen, as projected in the realistic scenario for 2040, requires 1 - 1.67 bcm of surface water. However, the average annual water availability in India is estimated to be 1,999.20 bcm[2] (As of 2019).

Thus, the water requirement for producing 16 MTPA of green hydrogen by 2040 is projected to be less than 0.05% of the total annual surface water availability in India. However, the local availability of water anywhere is subject to variability based on monsoons, allocations to other industries, and allocations to agriculture & domestic consumption. To evaluate water availability at a specific location, a separate study should be undertaken to map water availability at that location. Further, the government could prioritize the green hydrogen sector for water allocation.
Thus, water availability at an aggregate level is not a major challenge / constraint for assessing the green hydrogen production potential across states.

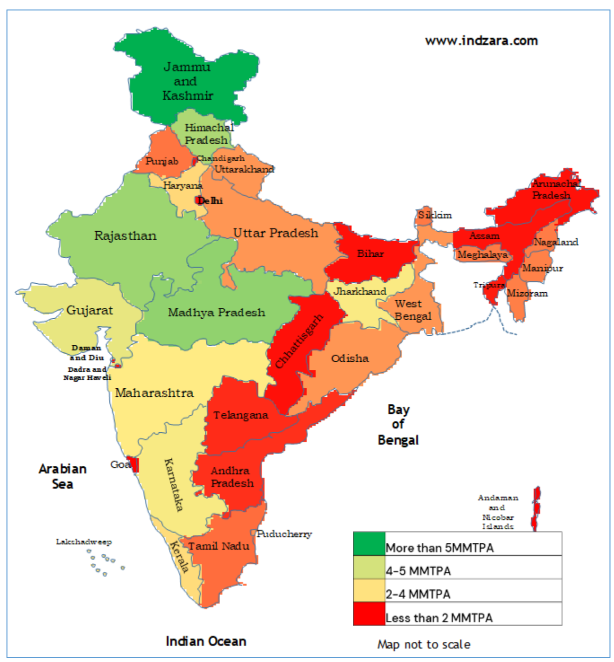
Renewable Energy Availability

Total potential of renewable energy in India is ~1652 GW, which can power ~56 MTPA of Green Hydrogen production.

Since, already installed RE capacity in India is ~172 GW (without large hydro) and ~217 GW (with large hydro), the remaining unutilized RE potential of ~1435 GW, if dedicated entirely to green hydrogen production, can generate ~51 MTPA of Green Hydrogen at the current efficiency.

The available RE potential is ~6-7 times the amount needed to produce the expected green hydrogen capacity planned for 2040, although a fraction of the RE power would be dedicated to decarbonizing the Indian

Figure 16: Map of Net H2 Potential in MMTPA (Based on All renewable combined) of each state



[1]https://www.brendandagg.com/documents/NAYLOR-2022-IWA-Full-Paper.pdf; Inputs from ICF's US based hydrogen experts
[2]http://cwc.gov.in/sites/default/files/reassessment-water-availability-volume-ii-november18.pdf

3. Blending of Hydrogen into Natural Gas pipelines

3.1 Why Blending?

India faces a critical challenge of balancing its growing energy demands with its ambitious green goals. Hydrogen blending in natural gas offers a promising solution. This approach involves mixing green hydrogen, produced from renewable electricity and water, with conventional natural gas. The resulting fuel has immense potential to propel India's green energy transition, offering several key advantages:

- **Reduced Emissions:** Blending green hydrogen with natural gas significantly reduces greenhouse gas emissions, compared to burning pure natural gas. This aligns with India's commitment to combat climate change.
- **Leveraging Existing Infrastructure:** India boasts of a vast network of natural gas pipelines. By repurposing these pipelines for the hydrogen blended natural gas, the country can significantly reduce the need for expensive new hydrogen infrastructure, saving time and resources.
- **Phased Transition:** Hydrogen blending allows for a gradual shift towards a hydrogen-based economy. This measured approach minimizes disruption to existing gas-powered systems and industries, easing the transition to clean energy.
- **Early Hydrogen Adoption:** Hydrogen blending can foster the development of a hydrogen ecosystem in India. This would include the developing hydrogen production facilities and blending stations, and applications like hydrogen-fueled vehicles. Early adoption can pave the way for a future, where green hydrogen is a key segment of India's energy landscape.
- **Cleaner Burning:** Even with a blend, hydrogen burns cleaner than natural gas, resulting in lower emissions of pollutants like nitrogen oxides. This contributes to improved air quality, particularly in urban areas.

3.2 Hydrogen Blending Pilot Projects in India

NTPC Project, Kawas (Blending of Green Hydrogen with PNG)

State-owned power generator NTPC Ltd. has commissioned the country’s first Green Hydrogen blending project. Green Hydrogen blending has begun in the piped natural gas (PNG) network of the NTPC Kawas township in Surat. The project is a joint effort between NTPC and Gujarat Gas Limited (GGL). The blending project supplies H2- NG (natural gas) to households in the Kawas township at Adityanagar, Surat. The Green Hydrogen in Kawas is produced through the electrolysis of water using power from a 1 MW floating solar project. The Petroleum and Natural Gas Regulatory Board (PNGRB) has initially approved 5% vol./vol. blending of Green Hydrogen with PNG, and the blending level will be scaled in phases to eventually reach 20%. Green Hydrogen when blended with natural gas significantly reduces carbon emissions, while maintaining the net heating content. By producing green hydrogen for blended natural gas, India would not only reduce its hydrocarbon import bill significantly, but also earn forex by exporting the surplus green hydrogen and green chemicals.

Torrent Power Project- Green Hydrogen Blending in City Gas at Gorakhpur

Torrent Power is implementing a Green Hydrogen pilot project, blending green hydrogen into the city gas distribution (CGD) network in Gorakhpur, Uttar Pradesh. Blending green hydrogen with the existing natural gas supply allows for a gradual transition towards cleaner and more sustainable energy choices. This pilot project will blend 2.5 % Green Hydrogen (GH2), produced using alkaline electrolysers, into the CGD network.

ATGL Gas Blending Project (Green Hydrogen with Natural Gas) in Ahmedabad, Gujarat

Adani Total Gas Ltd (ATGL), co-promoted by Adani Group and Total Energies, has initiated a Green Hydrogen production and blending pilot project, utilizing cutting-edge technologies to blend Green Hydrogen (GH2) with natural gas, which is supplied to over 4,000 residential and commercial customers in Ahmedabad. The project aims to gradually increase the percentage of GH2 in the blended gas to up to 8 % or more, subject to regulatory approvals. Upon successful completion of the pilot, ATGL plans to gradually expand the supply of GH2-blended fuel to larger sections of Ahmedabad and other regions under its license. This phased approach will allow for a controlled and well-monitored rollout of GH2 blending, ensuring optimal performance and safety

3.3 Challenges to Hydrogen Blending

While hydrogen blending in natural gas offers a promising path towards a greener future, significant challenges must be addressed before its widespread adoption becomes a reality. These hurdles span infrastructure concerns, safety considerations, and economic realities, requiring innovative solutions to ensure the smooth integration of hydrogen into India's existing natural gas network.

Technical Challenges	**Material Compatibility** • Transmission pipeline limits may vary between 5%-10% based on literature review, but individual pipelines may have lower limits determined by key factors such as material, age, operating pressure, and pipeline cracks. • Fertilizer industry (particularly Urea manufacturers) may face loss in efficiency for a hydrogen blending concentration greater than 2% by volume (in its SMR process). • Current CNG storage tanks have a blending limit of 2%. **Leakage and safety concerns** • Hydrogen's small molecule makes it more prone to leaks than natural gas. • Hydrogen can corrode existing pipelines (embrittlement), therefore requiring regular inspections and maintenance.
Commercial Challenges	**Cost Implications** • Developing business models incorporating infrastructure changes required for blending more than 2% hydrogen by volume in natural gas. • While deblending is technically viable, commercially, cost of deblending will result in approximately a 20% increase in CNG price (excluding the hydrogen cost)/ 50% jump in Urea price (if all costs are passed on to the customers). • Additionally, more CO2 is needed for production of Urea, to maintain the mass balance of Urea.
Regulatory Challenges	**Regulatory Framework** • Currently the PNGRB Act has no provision for H2 blending or pure hydrogen in the pipelines, thus requiring modifications to regulate hydrogen distribution through the existing pipeline infrastructure. • Several other PNGRB regulations need modifications to allow for blended hydrogen or hydrogen distribution. • Safety regulations need to be modified to accommodate blended hydrogen/pure hydrogen in NG pipeline infrastructure..

Overcoming these challenges is crucial to the implementation of a Hydrogen economy in India. ICF has conducted technical, commercial, and regulatory studies to identify means to overcome these problems. Findings from each of these studies have been presented in subsequent sections.

4. Technical Study

Key Findings

The primary goal of the technical study is to pinpoint any difficulties in utilizing current pipelines for blending or repurposing, with particular emphasis on analyzing the hydrogen blending limits for end-users and the existing transportation network and distribution system. This initiative seeks to examine the potential constraints and opportunities in incorporating hydrogen into natural gas pipelines and city gas distribution networks.

To assess blending limits in existing NG infrastructure, a literature review was conducted including 19 published documents and 17 pilot projects conducted worldwide. Apart from the literature review, stakeholder consultations with GAIL(India) Limited, PIL (Pipeline Infrastructure Limited) and EIL (Engineers India Limited) and Honeywell were also conducted. Our key findings were presented to a wider audience through a stakeholder workshop organized by PNGRB. Key Insights from all avenues are summarized in the Table below.

Table 7: Blending Limit in Various Components

S.NO.	Element	Blending Limit (without modifications)	Blending Limit (with modifications)	Key Remarks/Retro fitment Solution
1	Compressor	2%-5%	15%-20%	Swapping gas turbines or internal combustion engines with electric motors
2	Electrically Driven Compressor	15%-20%	-	-
3	Valve	10%	-	Required new equipment
4	Gas Filter	10%		Required new equipment
5	Fuel Filter	10%		Required new equipment
6	Odorant	15%	-	
7	Insulation Joint	10%-20%	-	
8	Volumetric Meters	10%		Required new equipment
9	Process gas chromatograph	<=0.2%	10%-20%	Replace helium cylinders with Argon Cylinder
10	Gas Meters	10% - 50%		
11	Gas Turbine	1%-2%	15%-20%	Modifications to increase limit to 15% - 20%
12	Feedstock/Reformer	2%	-	Lower efficiency. Requires deblending solution
13	Burner/Gas Stove	10%	20%-100%	
14	CNG Vehicle fuel Tank	2%		Requires deblending solution
15	Domestic Appliances	20%		
16	Transmission pipeline (Steel)	5%-10%	-	-
17	Distribution pipeline (PE)	25%-100%	-	-

18	Condensing and Steam Boilers	5%-10%	20%-100%	

Transmission Lines

- In gas transmission lines, a generally accepted blending limit of 5%-10% is observed (based on European Literature), with case-specific assessments and considerations recommended for material sensitivity. This limit is for a Steel pipeline and a pressure of more than 16 Bar.

Distribution Lines

- Distribution lines, due to their lower operating pressure, can achieve a higher blending rate of up to 25-100% (based on European Literature reviews). The 25% limit is set for a steel pipeline with gas pressure < 16 Bar. However, a 100% limit is feasible for a plastic pipeline with gas pressure < 16 Bar.

Compressor Station

- Compressor stations can generally tolerate blending levels between 2% and 5%. This limit is for centrifugal gas driven compressors. Electrically driven compressors have a higher tolerance limit, allowing for hydrogen blending of up to 15%-20%.

Measurement Devices

- Blending limits vary among measurement devices like volumetric meters, gas meters, and process gas chromatographs. Volumetric meters have a blending limit of approximately 10%, gas meters can tolerate blending up to 50%, but process gas chromatographs need replacement and can only tolerate a blending limit of around 0.2%.

Valves

- Valves can withstand hydrogen blending levels of up to 10%, but their metallic components are susceptible to hydrogen embrittlement.
- Elastomers used in the valves are resistant to chemical reactions but may experience leakage.

Pilot Projects

- Pilot projects have indicated that current blending limits range from 2% to 12%. (These limits are based on case-specific analyses)

Storage

- Porous storages are sensitive to hydrogen blending, making it challenging to establish a clear blending limit.
- Salt caverns are impervious to gas, and the salt's plastic nature makes it resistant to fractures and loss of impermeability. Microorganisms can't survive in highly concentrated brine, so biological reactions are absent. Hence, salt caverns can accommodate even pure hydrogen.

End User

- In feedstock applications, 2% is the blending limit.
- For domestic use, blending up to 20% is feasible, but may require retrofitting.
- CNG vehicles face a limitation of 2% blending due to constraints imposed by the fuel tank material.
- Gas turbines have a stringent 1% blending limit. (Stakeholder consultations suggest this limit may be 2%).
- Boilers can effectively handle blending levels between 5% and 10%.

Concluding Remarks

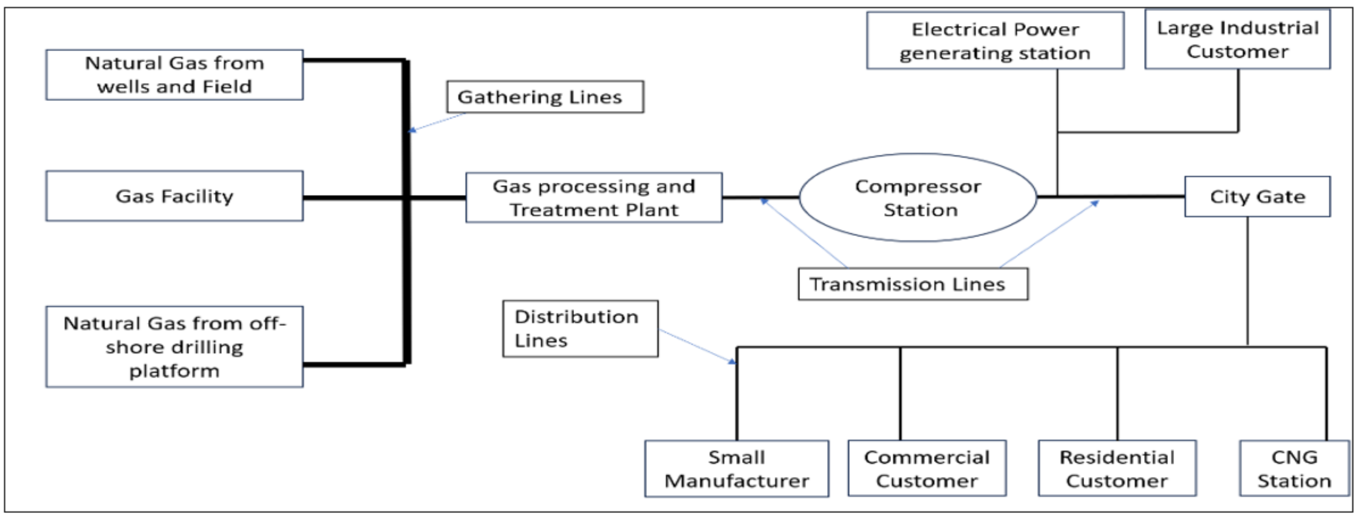
On a network-wide level, blending up to 2% is feasible with minimal adjustments. Hydrogen blending up to 10% is technically possible, but needs case-specific analysis, while blending exceeding 10% presents a significant challenge, requiring substantial system changes.

Disclaimer: The blending limits prescribed here are based on literature reviews and stakeholder consultations, however, in case of OEMs/Actual testing, different results may come up viz. blending limit of Turbine in the study is 1%-2% while PIL testing suggests that their turbine can handle up to 5%-10% blending without any major challenges

4.1 Value Chain of NG and Pipeline Industry

This section describes the components in the natural gas (NG) value chain and pipeline system. The NG pipeline value chain starts with gathering lines, which collect gas from production sources like drilling operations and wellheads. These lines feed high-capacity transmission pipelines that transport gas over long distances, often crossing state and national borders. Closer to the end consumers, distribution lines serve as the local distribution network. These pipelines deliver natural gas to residential, commercial, and industrial customers within a particular region. The city gate station is positioned at the juncture where natural gas leaves the high-pressure transmission lines and enters the local distribution network. This critical entity regulates the pressure and flow of natural gas in the local distribution network, ensuring a safe and reliable supply to homes and businesses. The figure below shows the various components present in the value chain of a NG pipeline.

Figure 17: NG Value chain



Detailed discussion of **major components of value chain** is presented below.

1) **Gathering Lines**- These lines are responsible for collecting natural gas from different sources, including production wells and drilling sites. These lines gather the gas and direct it into the broader transmission system. They transport natural gas from the production site, often referred to as the well pad, to another facility for additional processing, or directly to the transmission line.

2) **Transmission Lines**- These high-capacity pipelines transport natural gas over long distances, sometimes across states or even countries. They operate at higher pressures and can move large volumes of gas efficiently. These are large pipelines (typically 200-1200 mm in diameter) that move gas for long distances around the country, often at high pressures (typically 15 – 100 bar). These pipelines are mostly made of steel (API 5L Grade B to X80) and some portions of the transmission pipeline also utilize other materials viz. MDPE, Wrought iron etc.

3) **Distribution Pipeline**- As the natural gas gets closer to its end consumers, distribution lines take over from the transmission lines. Distribution pipelines form the local distribution network, serving homes, businesses, and industries within specific regions. Distribution lines operate at lower pressures (less than 15 bar) than transmission lines and are equipped with regulator stations to reduce the pressure to levels suitable for safe use in homes and businesses. Distribution pipelines may be made of steel, but high strength plastic or composites are being increasingly used.

4) **City Gate**- "City Gate" typically refers to a crucial point in the natural gas distribution network, where high-pressure transmission pipelines meet low-pressure distribution pipelines. City Gates are equipped with control and regulation systems that help manage the pressure and flow of natural gas, as it transitions from high-pressure transmission pipelines (operating pressure > 15-16 bar) to the lower-pressure distribution pipelines (operating pressure < 15-16 bar). This ensures that the gas is delivered safely and consistently to end consumers. City Gates contain measurement and monitoring equipment to track the volume and quality of natural gas as it enters the distribution network.

Components of Transmission and Distribution Natural Gas Pipeline

1) Transmission pipelines designed to move large volumes of gas over long distances at high pressures are a crucial part of the natural gas distribution network. They serve as the primary means for transporting natural gas from production fields to storage facilities and distribution networks. The major components of the natural gas transmission pipeline are described below.
2) **Pipeline Coating Material**- Coating facilities play a crucial role in the preservation of pipelines, safeguarding them against corrosion when they are installed underground. The primary objective of the coating is to shield the pipelines from corrosion and rust stemming from moisture, potentially corrosive soils, and defects that may have occurred during construction. Various coating methods are employed.
3) **Compressor Stations**- To ensure a continuous flow, natural gas is transmitted at high pressure through the interstate pipeline. However, to maintain the requisite pressure within the pipeline, the gas must be periodically compressed. These compression procedures are executed at compressor stations, positioned at regular intervals along the approximately 100 to 500 km long pipeline. At these compressor stations, the natural gas undergoes compression, which is carried out using either a turbine, motor, or engine-driven system. This compression process ensures that the gas maintains the necessary pressure as it travels through the pipeline.
4) **Metering Stations**- Interstate natural gas pipelines contain metering stations at regular intervals to facilitate the continuous monitoring, management, and accountability of the gas within the pipelines by both pipeline and local distribution companies. Fundamentally, these metering stations are responsible for quantifying the gas flow along the pipeline, enabling pipeline companies to maintain comprehensive records of the gas's transit. These stations are equipped with specialized meters designed to measure the natural gas as it flows through the pipeline, without causing any disruption to its movement. Their primary function is to gauge the flow of natural gas and make necessary pressure adjustments to the gas being received from or delivered to other systems.
5) **City Gate Stations-** In most distribution systems, natural gas is sourced from transmission pipelines and directed through one or more designated city gate stations, also referred to as town border or tap stations. At these stations the gas pressure is adjusted from the levels found in the transmission pipeline, to those suitable for the distribution system. The distribution network operates at a pressure range of about 1-20bar, which is significantly lower than the pressure in transmission pipelines that operate at around 35–100 bar. City gate stations primarily employ metering devices and pressure regulators to control gas flow and pressure, to maintain the desired and safe pressure levels in distribution systems. As an additional safety measure, odorant may be added to odorless gas received at these stations, typically at a concentration of three-quarters of a pound per million cubic feet.
6) **Valve-** Interstate pipelines are equipped with an extensive array of valves distributed over their entire length. These valves, functioning as gateways, are typically left in an open position to facilitate the unimpeded flow of natural gas. However, there are numerous scenarios that necessitate flow restrictions, including emergency shutdowns and routine maintenance. For instance, when a particular section of the pipeline requires replacement or maintenance, valves situated at both ends of that segment can be closed to provide engineers and work crews with a secure environment for their tasks. Typically, these valves are strategically positioned every 10 to 35 miles along the pipeline.

4.2 Literature Reviews: Hydrogen blending limit on various components of the Natural Gas Pipeline.

In the preceding sections, various components of the pipeline, such as valves and compressors, were discussed. This section will concentrate on the components of the key elements of the NG pipeline value chain. It's crucial to evaluate pinpoint individual components within key elements, as the blending limit is determined by the "weakest link

Transmission System

Before delving into the exact details of the hydrogen blending limit of a transmission line, this section will focus on how hydrogen blending affects different materials. The main problem with hydrogen blending is hydrogen embrittlement, a phenomenon where hydrogen infiltrates a susceptible material, leading to a significant reduction in ductility, which increases the risk of cracking and failures at stresses below the material's yield stress.

In At room temperature, molecular hydrogen (H_2) dissociates into individual atoms that are adsorbed onto metal surfaces. If these hydrogen atoms do not recombine, they can be absorbed into the bulk material, where they diffuse through the crystal lattice. This diffusion is driven by a combination of the material's solubility and the hydrogen's diffusion characteristics.

Various mechanisms have been proposed to explain hydrogen embrittlement, including Hydrogen Enhanced Decohesion (HEDE) or Hydrogen Induced Decohesion (HID), which suggests that hydrogen weakens atomic bonds, grain boundaries, and interfaces within the material. Another mechanism, Hydrogen Enhanced Localized Plasticity (HELP), posits that hydrogen ingress in areas of high stress, such as crack tips, shields dislocations and obstacles, reduces the internal stress fields and facilitates dislocation mobility, leading to localized plastic deformation. Additionally, the Adsorption Induced Dislocations Emission (AIDE) mechanism proposes that the chemisorption of hydrogen at strained areas like crack tips facilitates the nucleation of dislocations, promoting plastic deformation. If hydrogen is blended into metals, these mechanisms could lead to a significant reduction in the material's mechanical integrity, increasing the risk of premature failure and limiting the material's usability in critical applications. Therefore, it is essential to determine the blending limit in transmission systems.

In transmission pipelines, where the pressure exceeds 16 bar, the blending limit for hydrogen (H2) typically ranges from 5% to 10%. The figure below tabulates the blending limit, the specific condition for the blending limit, the issues encountered while blending, and the mitigation plan in the transmission system for studies conducted in various regions. The blending limit presented in the table is derived from literature reviews and is estimated for steel pipelines at pressures greater than 16 bar. However, the actual achievable blending limit is contingent on various factors, including the composition of natural gas, the grade of steel used, and other factors. A key challenge in blending H2 with natural gas is the uncertainty about the long-term effects of H2 on pipeline materials. Cracks, stress levels, and the frequency of pressure fluctuations in the pipeline also impact the blending limit and require thorough assessment.

To address these issues, mitigation measures are essential. These measures may include de-blending solutions for customers sensitive to hydrogen, and on-site blending to reduce the demand for de-blending. Additionally, system-specific analyses and more research into the effects of hydrogen on materials are required to comprehensively address the challenges associated with H2 blending in transmission pipelines.
Different grades of steel have different levels of susceptibility to hydrogen embrittlement. Steel grades such as X42, X46, X52, X60, X65, and X70 are designed to operate under increasing pressure as the grade number rises. For instance, X42 is used in lower-pressure applications, while X70 can handle much higher pressures. As the operating pressure (under which steel is used) increases, so does its susceptibility to hydrogen

embrittlement, which in turn reduces the permissible blending limit of hydrogen with natural gas. Generally, X52 is considered a threshold grade; steels up to X52 are less prone to hydrogen embrittlement and are often deemed acceptable for use with hydrogen-admixed natural gas. However, steel grades above X52, such as X60 and higher, exhibit a greater degree of hydrogen embrittlement, making them more vulnerable to cracking and failure when exposed to hydrogen, especially under high-pressure conditions. The higher susceptibility to embrittlement, of high-grade steel capable of handling high pressure, must be carefully evaluated to avoid compromising the structural integrity of transmission pipelines.

Table 8: Blending limit in transmission pipeline as per literatures.

Study	Country/Region	Blending Limit	Specific Condition for Limit	Issues	Mitigation Plan	References
The limitations of hydrogen blending in the European gas grid	EU	10% [a]	Limit is from pipeline perspective i.e., when pipeline material is steel and pressure > 16 bar. [a]	The achievable blending level depends on various factors, such as the origin and composition of the natural gas. [a] There are still many uncertainties regarding the long-term effect of H2-on various materials (pipes, devices, etc.). [a] Different grades of steel shows different degree of hydrogen embrittlement. [a]	De-Blending measures need to be taken by the Customer (Hydrogen sensitive). * [a] Implementing on-site blending at industrial sites can decrease the requirement for deblending measures within the natural gas grid. [a]	(Jochen Bard, n.d.)
Review of hydrogen tolerance of key Power-to-Gas (P2G) components and systems in Canada: final report	Canada	Up to 5% [e]	This limit is specified from perspective of Canadian Pipeline. This limit is possible only in some parts of the transmission grid of Canada NG pipeline. [e]	The hydrogen blending limit varies by system due to grid integrity, safety, energy transport capacity, and end-use requirements.[e] Hydrogen embrittlement effect varies with variation of steel grades. [e]	System specific analysis is necessary. [e] Further research required in the subject "Effect of hydrogen on different grades of steel". [e]	(Yoo, et al., n.d.)
Transformation of the European natural gas grid into hydrogen	EU	10% [j]	Limit is from pipeline perspective i.e., when pipeline material is steel and pressure > 16 bar. [j]	To assess the impact of hydrogen over a pipeline's lifespan, factors such as the presence of cracks, the frequency of pressure fluctuations, stress levels, and weld hardness must be evaluated. [j]	Appropriate measures will be required depending on the presence of cracks and other defects. [j]	(Walter, n.d.)

Distribution System

This section will focus on the blending limit in the distribution network. From a material and operating pressure standpoint, the H2 blending limit differs for different pipeline configurations. In cases where the pipeline is constructed with plastic material and the pressure remains below 16 bar, the theoretical H2 blending limit can be as high as 100%. However, for pipelines made of steel, operating at less than 16 bar, the H2 blending limit is notably lower, at 25%. This variation underscores the significance of material compatibility and pressure levels in determining the safe extent to which hydrogen can be blended into natural gas. In steel pipelines, an increase in pressure leads to a greater degree of hydrogen embrittlement. For plastic pipes, higher pressure results in increased hydrogen leakage through the pipe walls. Gas leaks can be characterized by mechanisms such as permeation, diffusion, and pneumatic leaks.

Permeation involves the adsorption of hydrogen on the metal surface, dissociation of hydrogen molecules, diffusion of hydrogen atoms through the metal, reassociation into molecules, and desorption on the opposite side.
Diffusion refers to the passage of hydrogen gas through polymer materials by molecular diffusion.
Pneumatic leaks occur when gas is transferred through a physical opening due to a pressure gradient.
Hydrogen permeates polymers at a significantly higher rate than natural gas. Although the economic loss from hydrogen permeation is negligible, it raises safety concerns, especially in confined spaces where hydrogen could accumulate. The total volumetric loss of gas increases with both the pressure and the concentration of hydrogen in the blend.
For polyethylene pipes, gas loss mainly occurs through the pipe wall, whereas in metal pipes, leaks primarily originate from joints, cracks, and seals due to the slower diffusion rates of hydrogen in metals. Research by Hodges et al. indicates that while hydrogen permeates polymers 6 to 7 times more than methane, leakage from permeation is less significant than leakage from pipe defects.
The Gas Technology Institute (GTI) conducted simulated leak experiments using gas blends containing 10%, 20%, and 40% hydrogen in methane, with orifice diameters of 0.003 in, 0.01 in, and 0.03 in, at pressures of 54 psig, 9 psig, and 0.3 psig. The results showed no preferential leakage of hydrogen through the orifices; however, the gas blend leaked at a higher rate as the hydrogen concentration increased. The study concluded that the flow rates of the simulated leaks corresponded to the ratios of the square roots of their specific gravities.

The table presented below shows the blending limit for the distribution system as per various studies. However, establishing these blending limits is not without challenges. Infrastructural changes may be necessary to accommodate higher hydrogen blending levels, which can be a substantial undertaking. Additionally, the sensitivities of certain customers to hydrogen must be considered, as increased blending levels can pose serious challenges for them. To address these issues and arrive at appropriate blending limits, further research and analysis is imperative. This will ensure that the blending of hydrogen gas into existing natural gas infrastructure is carried out safely and efficiently, facilitating the transition to cleaner energy sources while minimizing risks and disruptions

Table 9: Blending limit in distribution system as per various studies.

Study	Country/Region	Blending Limit	Specific Condition for Limit	Issues	Mitigation Plan	References
The limitations of hydrogen blending in the European gas grid	EU	25%/100% [a]	**25%** Limit is given from pipeline material perspective (Pipeline material is Steel, Pressure < 16 Bar). **100%** limit is given from pipeline material perspective (Pipeline material is plastic, Pressure < 16 Bar).	Infrastructural adjustments are needed. [a] The introduction of hydrogen blending can pose challenges for end use customers and storage applications. [e]		(Jochen Bard, n.d.) (Yoo, et al., n.d.)

The limitations of hydrogen blending in the European gas grid	EU	2%/30% [a]	**2%** limit is given by presence of CNG-refuelling stations due to the 2% hydrogen admixture limitations of gas-fuelled cars. **30%** limit is based on House installation i.e., blending up to 30% is acceptable since household equipment can tolerate this much blending level.			(Jochen Bard, n.d.)

Compressor Station

The compressor in a compressor station can be divided into two main components, each serving distinct but interdependent functions. These components are the compressor itself and the compressor drive, which is typically a motor or a gas engine generator.

It is observed that blending limits within compressors typically range from 2% to 5%. The table below provides a comprehensive overview of H2 blending limits in compressors as documented in various literature sources. These limits are for Gas driven compressors. In the case of electrically driven compressors, the blending limit is significantly higher at 15-20%.

Table 10: H2 blending limit in compressor station as per literature review.

Study	Country/Region	Blending Limit	Specific Condition for Limit	Issues	Mitigation Plan	References
The limitations of hydrogen blending in the European gas grid	EU	5% [a]	Not Specified. [a]	The technical issues are inadequately specified. [a] An increase from 10% to 20% H2 by volume adds around 50% of the investment costs for new compressors. [a] Demand for de-blending can occur because mechanical drive of compressor used in gas grid is hydrogen sensitive. [a]	Swapping gas turbines with electric motors is a retrofit option. [r]	(Jochen Bard, n.d.) (Kevin Topolski, n.d.)
Review of hydrogen tolerance of key Power-to-Gas (P2G) components and systems in Canada: final report	Canada	2% [e]	This limit is given for the whole compressor station. [e]			(Yoo, et al., n.d.)
Transformation of the European natural gas grid into hydrogen	EU	5% [j]	This 5% limit is derived from the fact that "Certain materials used in compressor has pressure limit of 6,8 bar". [j]			(Walter, n.d.)

Now the focus will be on different types of compressors and their compatibility with H2 blending. Compressors are in general of two types viz. dynamic and positive displacement compressors. When considering the compatibility of different compressor types with hydrogen blending, it's essential to note that dynamic compressors, specifically centrifugal and axial compressors, present unique challenges. Centrifugal compressors encounter operational difficulties with high hydrogen content due to the gas mixture's low molecular weight, necessitating material adjustments and larger circumferential dimensions. To address this, multiple-stage compressors operating at high rotational speeds become necessary. In contrast, axial compressors may experience decreased head pressure and capacity when used with H2-blended gas, potentially warranting the establishment of additional gas compressing stations to mitigate these effects. Table shown below provides the comparison of centrifugal and axial compressors.

Table 11: Comparison of dynamic compressors based on literature review.

Study	Country/Region	Type of Compressor	General Issues with Compressor	Action Plan/Mitigation Plan	References
Analysis of compression and transport of the methane/hydrogen mixture in existing natural gas pipelines	Poland/EU	Centrifugal Compressor (Dynamic compressor with Radial flow)	Centrifugal compressors pose more operational challenges than reciprocating compressors due to the low molecular weight of gas mixtures with high hydrogen content, necessitating different materials and larger circumferences. [g]	To achieve high hydrogen pressures, these compressors require multiple stages operating at high rotational speeds, as well as special seals and high mechanical tolerances. [g] Depending on the hydrogen mass flow rate, various types of centrifugal compressors are proposed viz. conventional multistage centrifugal compressors for lower flow rate and advanced centrifugal stages – the eight-stage integrally geared centrifugal compressor for higher flow rate. [g]	(Andrzej Witkowski, n.d.)
Clean energy and the hydrogen economy	UK	Large axial compressor (Dynamic compressor with axial flow)	Using large axial compressors originally intended for pure natural gas to compress H2-NG blends (HENG fuel) can lead to reduced compressor head pressure and lower capacity. [h]	To accommodate additional capacity and provide support for existing ones, it may be necessary to establish additional gas compressing stations. [h]	(Al Rafea, n.d.)

When comparing centrifugal compressors to reciprocating compressors for hydrogen compression, several factors favor the latter. The low molecular weight of hydrogen necessitates increased rotational speed in centrifugal compressors with higher hydrogen concentrations, increasing the stress on the impeller. This raises reliability and durability concerns. Hydrogen's impact on fluid density at the compressor inlet can lead to off-design conditions and operational issues. Moreover, hydrogen blending can reduce the energy density of the fuel, limiting prime mover capacity and overall compressor station capacity. Reciprocating compressors, with their flexibility and reliability in handling varying gas compositions, are more suitable for hydrogen compression applications.

City Gate Station

A city gate station in a natural gas pipeline system is a crucial facility that serves as a gateway between the high-pressure interstate natural gas transmission pipelines and the lower-pressure distribution pipelines that supply gas to homes, businesses, and industries within a city or metropolitan area. At the city gate station, the gas pressure is reduced for compatibility with distribution lines. Additionally, the gas is typically odorized for safety reasons, and sometimes measured for billing purposes before it is further distributed to end-users. A city gate station, or CGS, primarily consists of essential components such as a filtration unit, metering unit, pre-heating unit, pressure regulation unit, and several flow control units. The key elements within a CGS include valves, filters, measuring meters, odorizers, and insulation joints. The table below presents the H2 blending limit in various elements of the city gate station.

Table 12: Hydrogen blending limit in various components of City Gas Station based on literature review.

Study	Country/Region	Component	Blending Limit	Specific Condition for Limit	Issues	Mitigation Plan	References
Hydrogen Impacts on Downstream Installations and Appliances	Australia	Gas filter	Up to 10% [s]	Not Specified	Blending enhances leakage rates through seals, joints and fittings. [s] Brittle failure of ductile steel components due to embrittlement. [s] Increased permeation rates through plastic pipes. [s]	Further research is needed to assess the impact of increased leakage rates, permeation rates, and embrittlement. [s]	(Engineering, n.d.)
Hydrogen Impacts on Downstream Installations and Appliances	Australia	Fuel Filter	Up to 10% [s]	Up to 10% hydrogen in natural gas blends is not likely to affect the existing component or change the risk profile. [s]			(Engineering, n.d.)
Hydrogen Impacts on Downstream Installations and Appliances	Australia	Odorizer	Up to 28% [l]	Not Specified			(Amy Myers Jaffe, n.d.)
Hydrogen Blending Impacts Study	USA	Insulation Joint	Not Specified		Insulation joints have hubs **and yoks** which are made up of **Steel** (ASTM A105, A106 or A694) and **Gaskets.** These elements are subjected to varying degrees of Hydrogen embrittlement. [b]		(Arun SK Raju, n.d.)

Metering Station

A metering station in a natural gas pipeline system is a critical facility designed to accurately measure the quantity of natural gas being transported. It typically includes various measurement devices, such as gas meters, which are essential for billing purposes and maintaining system integrity. The tablepresented below shows the gas tolerance in terms of hydrogen blending for various types of meters.

Table 13: Hydrogen blending limit of various types of meters.

Study	Country/Region	Component	Blending Limit	Specific Condition for Limit	Issues	Mitigation Plan	Refrences
The limitations of hydrogen blending in the European gas grid	EU	Volumetric meters	Up to 10% [a]	This is theoretical limit	Various types of meters using different measurement principles will necessitate different types of modifications. [a]		(Jochen Bard, n.d.)
The limitations of hydrogen blending in the European gas grid Admissible hydrogen	EU UK	Process gas chromatograph	<=0.2% [a]	This limit is for meters which are already installed in NG pipeline systems. [a]	Additional carrier gas is needed, incurring extra expenses. [a] The current generation of process gas chromatographs (PGC) uses helium as the	retrofitting an additional separating column using argon as a carrier gas for hydrogen	(Jochen Bard, n.d.)

concentrations in natural gas systems					carrier gas and, as a result, are unable to detect hydrogen due to the closeness of their thermal conductivities (helium = 151 W/m*K; hydrogen = 180 W/m*K.). [n]	detection or by employing new process gas chromatographs. [n]	
NREL- Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues	USA	Gas Meters	<50% [c]	"The deviation of a gas meter with hydrogen blends varies with the meter design. This deviation was found to be acceptable based on the requirement for recalibration (less than 4%) when a gas mixture containing less than 50% hydrogen is being measured." [c.]	For blends > 50% hydrogen needs to be retuned. [c] Gas characteristics are progressively deviated. [f]	The detectors in the meters should be recalibrated. [f] Further research is needed on recalibration, gaskets and sealings need to be assessed for suitability, safety and durability. [c]	(M. W. Melaina, n.d.)
NREL- Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues	USA	Gas meter with polymeric membrane	Up to 50% [c]	This limit is based on experimentation done by gallus. [c]			(M. W. Melaina, n.d.)
NREL- Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues	USA	leather and plastic diaphragm gas meters	Up to 17% [c]	This limit is based on experimentation performed in Polman's study. The results indicated that for mixtures up to 17%, the required capacity is not affected by adding hydrogen in natural gas.[c]			(M. W. Melaina, n.d.)
Transformation of the European natural gas grid into hydrogen	EU	1) Turbine gas meter 2) Rotary Displacement gas meter 3) Ultrasonic meter 4) Diaphragm Gas meter	10% [j]	Not Specified			(Walter, n.d.)

*- The detectors in the meters should be recalibrated: It must be noted that In case of Vol to vol meters no/minimal calibration is required while in vol to mass meters, recalibration is needed for small % of hydrogen.

Valves

Valves are crucial components in both, natural gas transmission and distribution systems, finding application in various facilities such as metering and compressor stations. Their primary function is to regulate and control the flow of gas within the pipelines. The table presented below provides information on the hydrogen blending limits in valves. This limit, typically restricted to approximately 10%, ensures the safe and reliable operation of valves within gas distribution systems.

Table 14: Hydrogen Blending limit of Valves.

Study	Country/ Region	Blending Limit	Specific Condition for Limit	Mitigation Plan	Refrences
The limitations of hydrogen blending in the European gas grid	EU	10% [a]	Not Specified but this is the general limit for all types of valves.		(Jochen Bard, n.d.)
Transformation of the European natural gas grid into hydrogen	EU	10% [j]	Not specified but this is the general limit for all types of valves particularly gas relief valve and shut off valve.		(Walter, n.d.)
The Potential to Build Current Natural Gas Infrastructure to Accommodate the Future Conversion to Near-Zero Transportation Technology	USA	Up to 30% [l]	General limit for all types of valves		(Amy Myers Jaffe, n.d.)
Sector Forum Energy Management /Working Group Hydrogen- Final Report	EU	< 10% [o]	This is based on the fact that available literature does not indicate difficulties for low hydrogen concentration (below 10 vol%). [o]	The soft sealing materials in pressure regulators, valves, and slam shut valves are crucial for safety and should be thoroughly examined to understand their performance with hydrogen at concentrations exceeding 10% by volume. [o]	(E. Weidner, n.d.)

Certain components of valves may not be suitable for use with hydrogen due to the risk of hydrogen embrittlement. Metals like steel, brass, and cast iron commonly used in valves can be vulnerable to hydrogen embrittlement. On the other hand, elastomers, which are often used in valves, tend to be compatible with hydrogen due to their chemical resistance. However, they can suffer from high rates of hydrogen gas permeation.

Managing potential leaks of hydrogen, which is known for its small molecule size, poses a challenge. Leaks occur in valves through two main pathways: 1) leakage through the seat and 2) leakage through the stem. To prevent leakage at the valve seat, metal-to-metal technology is preferred, which uses a flexible and resilient metal disk to establish a secure seal. Commonly used materials like soft graphite are permeable to hydrogen gas and ineffective in preventing leaks. Therefore, hard metals and precisely machined gaskets are essential for creating an effective and reliable seal in hydrogen applications.

Storage Methods

Natural gas storage can broadly be categorized into two types: Underground and above-ground storage. Among the underground storage methods, there are three major options viz. depleted gas fields, pore storage and salt caverns. Depleted gas fields are geological traps that were once filled with hydrocarbons but now serve as repositories for natural gas. Pore storage, on the other hand, contains natural gas within underground rock formations or reservoirs possessing high porosity and permeability. Lastly, salt caverns are artificially created cavities constructed within salt deposits and used to store natural gas.

- Porous storages are sensitive to hydrogen blending, making it challenging to establish a clear blending limit.
- Salt caverns are impervious to gas and the salt's plastic nature makes it resistant to fractures and loss of impermeability. Also, microorganisms cannot survive in highly concentrated brine, so biological reactions are absent. Hence, salt caverns can accommodate even pure hydrogen.

Above-ground storage methods primarily fall into two categories: LNG/CNG storage, and pipe storage. LNG and CNG storage typically involve vessels constructed from steel, while pipe storage entails using sections of pipelines specifically designated for natural gas storage. The table provided below shows the hydrogen blending limit for various storage methods.

Table 15: Hydrogen blending limit in various Storage methods.

Study	Country/Region	Storage Method	Blending Limit	Specific Condition for Limit	Issues	Mitigation Plan	References
The limitations of hydrogen blending in the European gas grid. Utilizing 'Power-to-Gas' Technology for Storing Energy and to Optimize the Synergy between Environmental Obligations and Economical Requirements. Transformation of the European natural gas grid into hydrogen	EU Canada	Pore/Porous Storage	0% [j, l]–10% [a]	In general, conflicting literature exists regarding blending limits, with some suggesting no tolerance, while specific pore storages can accommodate up to 10% hydrogen blending by volume. [a]	Hydrogen can act as a substrate for sulfate-reducing bacteria, posing a risk of bacterial growth. This can result in the production of hydrogen sulfide, hydrogen consumption, and potential damage to the storage material's permeability. [a] Demand for de-blending can occur to protect them. [a]	According to DVGW G 262, it is advisable to restrict the injection of hydrogen into pore storages.	(Walter, n.d.) (Amy Myers Jaffe, n.d.) (Jochen Bard, n.d.)
The limitations of hydrogen blending in the European gas grid. The Potential to Build Current Natural Gas Infrastructure to Accommodate the Future Conversion to Near-Zero Transportation Technology	EU USA	Salt Cavern	100% [a] 55% (with adjustments) [l]	"It has been assumed that for 55% hydrogen blending, investment in de-sulphurization was made." [a] "Loss of permeability has been neglected." [a]	The limit is broadly defined and depends on the geometry of the gas storage facilities; nevertheless, a 20% blend could result in the gradual loss of individual storage facilities, necessitating de-blending measures. [a]		(Jochen Bard, n.d.) (Amy Myers Jaffe, n.d.)
Hydrogen Blending Impacts Study Transformation of the European natural gas grid into hydrogen	USA EU	Salt Cavern	100% [b, j]	Salt caverns are impervious to gas and the salt's plastic nature makes it resistant to fractures and loss of impermeability. Almost no microbes can survive in highly concentrated brine. Hence, salt caverns are not only suitable for storage of hydrogen blends, but also pure hydrogen.			(Arun SK Raju, n.d.) (Walter, n.d.)
Hydrogen Blending Impacts Study The Potential to Build Current Natural Gas Infrastructure to Accommodate the Future Conversion to Near-Zero Transportation Technology	USA USA	Manufactured Vessels	Not Specified [b] Around 30% [l]		Several metallic materials in the natural gas pipeline system, including high strength steels, are susceptible to mechanical integrity loss due to hydrogen embrittlement. Therefore, natural gas and hydrogen blends stored in manufactured above-		(Arun SK Raju, n.d.) (Amy Myers Jaffe, n.d.)

					ground natural gas storage containers can result in material degradation and failure. [b]		

End Users

This section discusses blending limits in end-user equipment. When it comes to using hydrogen as a feedstock, the feasible blending limit is set at 2%. Even minor increments, particularly in sectors reliant on consistent gas quality, like material applications in the field of chemistry or applications requiring constant temperatures, can pose substantial risks to process reliability. This is because hydrogen in its pure form, with only one-third the calorific value of natural gas, isn't suitable for all high-temperature applications. Even at this relatively low blending percentage, PSA (Pressure Swing Adsorption) technology is required to separate hydrogen from natural gas, which adds to the cost of the process.

In Compressed Natural Gas (CNG) vehicles, the blending limit for hydrogen is restricted to 2%. This limit has been imposed as a precaution due to the potential risk of material failure caused by hydrogen embrittlement in gas tanks, particularly in older vehicles.

Notably, the CNG fuel tanks themselves adhere to a blending limit of 2%. These tanks are constructed from high-tensile strength steel, which allows for thinner walls and reduced weight. However, this specific type of steel is more susceptible to hydrogen embrittlement. Hence, the 2% blending limit serves as a protective measure to mitigate these risks.

For gas and internal combustion (IC) engines, the blending limit for hydrogen in natural gas varies within a range of 5% to 10%. This limit is primarily linked to the concept of knocking resistance, often represented by the Methane number. The addition of hydrogen to natural gas tends to reduce the Methane number, subsequently affecting the knocking resistance of the mixture. It's crucial to note that the composition of natural gas plays a pivotal role in determining the blending limit. When natural gas contains higher levels of hydrocarbons that inherently possess a lower Methane number, the blending limit is further reduced. Hydrogen blended into natural gas, can accelerate the flame speed and reactivity, resulting in higher cylinder peak pressures, lower Methane number, increased combustion, and end-gas temperatures. These factors collectively elevate the risk of engine knock and contribute to higher emissions of nitrogen oxides (NOx). This intricate interplay of variables underscores the importance of considering natural gas composition and its consequences when determining the blending limit for hydrogen in gas and IC engines. In the context of gas turbines, the blending limit for hydrogen is notably stringent, hovering at approximately 1%. However, as per stakeholder consultations, this limit is 2%. In case of boilers, the blending limit varies from 5% to 10%. The table below shows the blending limit in different end user equipment.

Table 16: Blending limit in various End user equipment.

Study	Country /Region	Usage/Equipment	Blending Limit	Specific Condition for Limit	Issues	Mitigation Plan	References
The limitations of hydrogen blending in the European gas grid	EU	Feedstock	2% [a]	This limit is when H2 Blended NG is used as feedstock in process. [a]	Even small admixture quantities can pose significant risks for process reliability. [a] Hydrogen blending can cause impairments to the energy efficiency of production processes. [a] Demand for de-blending can occur for hydrogen sensitive customers. [a]	Separation of H2 from NG is possible at customer end by using technologies e.g., PSA, but it adds to production costs.. [a]	(Jochen Bard, n.d.)
The limitations of hydrogen blending in the European gas grid	EU	Domestic Gas Piping	20% [a]	This limit is for pipes in household system. [a]	The calibration system of gas meters may not be able to tolerate this limit. [a] Long term durability of elastomers is still being researched; hence its compatibility		(Jochen Bard, n.d.)

					with this level of blending is unknown. [a] Meter expansion is possible, to avoid it, calorific value reconstruction system needs to be introduced at distribution grid level, if we want to increase the limit from 10% to 20%. [a]		
Review of hydrogen tolerance of key Power-to-Gas (P2G) components and systems in Canada: final report	Canada	Gas Stove	10% [e]	Not Specified			(Yoo, et al., n.d.)
NREL- Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues	USA	Domestic Appliances	<=28% [c]	Domestic appliances must be properly serviced for this limit. [c]	The long-term material compatibility of domestic appliances with hydrogen and natural gas mixtures beyond 15 years from now remains uncertain. [c] Preferred operating conditions of Natural gas engines and modern gas turbines may not align with hydrogen concentration. [c]		(M. W. Melaina, n.d.)
Hydrogen-enriched natural gas as a domestic fuel: an analysis based on flash-back and blow-off limits for domestic natural gas appliances within the UK.	UK	Domestic Appliances	23.4% by mol [d]	It is based on Wobbe's index i.e., if Blending goes beyond this (23.4%) then the Wobbe's index will drop 48.17 MJ Nm3, and end-users will not receive the minimum energy output promised by their energy supplier.[d]			(Daniel R. Jones, n.d.)
Hydrogen Blending Impacts Study	USA	Domestic Appliances	5%-20% [b]	"This is the acceptable range without significant impact on safety and operation of end-use appliances." [b.]	Higher hydrogen levels can cause an increase in the adiabatic combustion temperature potentially resulting in local component overheating or higher emissions of nitrogen oxides (NOX). There is an increase in the laminar combustion velocity with addition of hydrogen, which poses a risk of potential flashbacks in household appliances.		(Arun SK Raju, n.d.)
Hydrogen-enriched natural gas as a domestic fuel: an analysis based on flash-back and blow-off limits for domestic natural gas appliances within the UK.	UK	Domestic Appliances	20% by mol [d]	Natural Hy project investigated the logistical transport, storage, and end-usage of HENG;13 within this project, and conducted trials in the Netherlands. They concluded that compositions of up to 20 mol% hydrogen were compatible with modern domestic natural gas appliances.			(Daniel R. Jones, n.d.)
The limitations of hydrogen blending in the European	EU	Gas Burners	10% [a, e, j] to 15% [l]	Up to 10%, no issues are expected. [a]			(Jochen Bard, n.d.) (Yoo, et al., n.d.) (Walter, n.d.)

gas grid. Review of hydrogen tolerance of key Power-to-Gas (P2G) components and systems in Canada: final report. Transformation of the European natural gas grid into hydrogen. The Potential to Build Current Natural Gas Infrastructure to Accommodate the Future Conversion to Near-Zero Transportation Technology	 Canada EU USA			For up to 20% blending by volume, modifications or additional measures may be needed. [a] Technically, retrofitting natural gas burners to operate with hydrogen blends of any fraction is feasible, but costs and complexity of retrofits tend to rise significantly beyond approximately 15% hydrogen content. [l]			(Amy Myers Jaffe, n.d.)
The limitations of hydrogen blending in the European gas grid. Review of hydrogen tolerance of key Power-to-Gas (P2G) components and systems in Canada: final report.	EU Canada	CNG Vehicles	2% [a, e, n]	This limit was imposed due to the risk of gas tanks in older vehicles suffering from material failure on account of hydrogen embrittlement. This is mostly for steel. [a]	Hydrogen embrittlement of steel is a possible cause for failure. [a] The need for de-blending can arise at CNG refueling stations due to the sensitivity of CNG vehicles to hydrogen concentration. [a]	With an increasing number of gas tanks made from materials that don't undergo hydrogen embrittlement, there's potential in the medium term to raise the threshold value of blending in compressed natural gas (CNG) filling stations. [a]	(Jochen Bard, n.d.) (Yoo, et al., n.d.) (Pinchbeck, n.d.)
Hydrogen Blending Impacts Study	USA	CNG Fuel Tank	2% [b]	This limit is based on international standards of many countries.	CNG tanks are made from high-tensile strength steel, enabling thinner walls and reduced weight, but this type of steel is vulnerable to hydrogen embrittlement. [b] CNG tanks in Europe are constructed with steel suitable for higher hydrogen levels, and replacing existing CNG vehicle fuel systems in diverse global regions is costly and time-consuming, given that CNG fuel tanks typically come with a 20-year lifetime guarantee. [b]		(Arun SK Raju, n.d.)
The limitations of hydrogen blending in the European gas grid. Admissible hydrogen concentrations in natural gas systems	USA UK	Gas Engines (IC Engine)	10% [a] 2%-5% [n]	This limit may be due to the knocking resistance i.e., Methane number. Addition of hydrogen in NG reduces methane number and hence the knocking resistance.	"Methane has methane number of 100 and hydrogen has methane number of 0 hence adding hydrogen in methane would reduce methane number and hence knocking resistance." [a] Natural gas composition is also an important factor since NG may contain higher hydrocarbons with reduced methane number, thus further reducing the blending limit. [a]		(Jochen Bard, n.d.) (Pinchbeck, n.d.)
Hydrogen Blending Impacts Study	USA	Engines/IC	10% [b]	It is a limit based on no-requirement for tuning i.e., at this	"Methane has methane number of 100 and hydrogen has methane number of 0 hence adding hydrogen in methane would reduce		(Arun SK Raju, n.d.)

		Engines		limit, no tuning would be required. Gas blends with more than 20% hydrogen require engine retuning and low swirl intakes to run optimally.	methane number and hence knocking resistance."		
The limitations of hydrogen blending in the European gas grid. Review of hydrogen tolerance of key Power-to-Gas (P2G) components and systems in Canada: final report. Transformation of the European natural gas grid into hydrogen. Admissible hydrogen concentrations in natural gas systems	EU Canada EU UK	Gas Turbines	1% [a, e, j, n]	1% limit is without any significant issues. [a]	Demand for de-blending can occur because it is hydrogen sensitive equipment. [a] **Flashback**- Hydrogen's combustion speed surpasses that of natural gas, and its rapid flame can shoot back into the fuel nozzle, posing a risk of high-temperature damage to gas turbine hardware. **Auto-ignition**- Hydrogen's high reactivity elevates the risk of auto-ignition in pre-mixing sections, necessitating a carefully designed combustor, with a multi-nozzle arrangement, to safeguard burners and nozzles from potential overheating and damage. **Thermal Instabilities**- Instability in the hydrogen flame can induce vibrations, disrupting gas turbine operation. This can be mitigated through a dependable monitoring and control system. **NOx Emissions**- Hydrogen elevates the adiabatic flame temperature, leading to increased NOx emissions. To counter this, lean premixed (LPM) combustors have been developed to minimize NOx emissions.		(Jochen Bard, n.d.) (Yoo, et al., n.d.) (Walter, n.d.) (Pinchbeck, n.d.)
Transformation of the European natural gas grid into hydrogen	EU	Condensing Boiler	10% [j]	Not Specified			(Walter, n.d.)
Transformation of the European natural gas grid into hydrogen	EU	Steam Boiler	5% [j]	Not Specified	Blending hydrogen into coal-fired boilers poses challenges in modifying burners and controlling NOx emissions, primarily due to hydrogen's significantly higher combustion speed compared to pulverized coal.		(Walter, n.d.)
Pilots	India	Blast Furnace	No Current Limit% *	TATA is conducting a pilot/trial study of blending hydrogen gas in the blast furnace at the Jamshedpur Plant. *			
Pilots	India	Gas Regulator	8%	This is the limit as per the Gujarat gas pilot program in NTPC Kawas Township.			

Pilot Projects

Numerous pilot projects have been conducted globally to assess the blending limits of hydrogen in transmission, distribution, storage, and end-use systems. The acceptable blending limits obtained from these case-specific pilots range from 2%-12%. The following Table provides an overview of these pilot projects, including key details and findings.

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Table 17: Pilot projects of Hydrogen blending in Natural gas infrastructure across the Globe.

S.NO.	Project Name	Project Period	Location	Network	Key Topics and Findings	% H2 Studied	% H2 Acceptable
1.	Hawaii Gas	1970-present	USA	T & D	Long-term hydrogen blending in natural gas distribution and transmission pipelines has been successfully demonstrated. There was no available measurement on hydrogen leakage, nor hydrogen-related failure.	10%-12%	12%
2.	Initial Assessment of the Effects of Hydrogen Blending in Natural Gas on Properties and Operational Safety, Phase 1	2015	USA and Canada	D	The examination assessed the impact of 5% hydrogen on non-metallic pipelines. The study examined the leakage rate of a 5% hydrogen blend through elastomer couplings.	5%	5%
3.	University of California Irvine (UCI) National Fuel Cell Research Center (NFCRC) Campus Hydrogen Microgrid	2016-present	USA	D	Odorants are not adequate for detecting leaks. Gas turbines exhibited a slight reduction in total fuel gas flow, with no adverse effects on emissions.	0% - 3.8%	3.8%
4.	M2018-008 Expansion of NYSEARCH RANGE Model & Study of Siloxane Concentration Limits	2019-2020	USA and Canada	D & E	The effect of blending on Wobbe numbers, combustion processes, yellow tipping, flame lifting, flame speed, flashback, and CO emissions was examined.	2% - 20%	10%
5.	Enbridge Low-Carbon Energy Project	2021-Present	Canada	D & E	A specific Gas Distribution Network had an upper limit of 5% hydrogen by volume. The upper limit for hydrogen was determined to be 2%, considering the local gas composition, heating equipment, and appliances.	0%-100%	5%(D) and 2%(E)
6.	P2G Ameland	2008-2012	Netherlands	D	Blending hydrogen up to 20% does not affect the infrastructure materials and service lines.	20%	20%
7.	Underground Sun Storage	2013-2018	Austria	S	Underground storage facilities can withstand hydrogen content of up to 10%.	10%	10%
8.	Energy Storage – Hydrogen injected into the Gas Grid via Electrolysis Field Test – Phase 1	2014-2020	Denmark	S, T & D	A long-term test at the facility was conducted with hydrogen concentrations reaching up to 12%.	15%	12%
9.	GRHYD	2014-present	France	D	Successful operation involving H2 injection up to 20% was performed for over 5 years.	0%-20%	20%

10.	ITM Power Thüga Plant	2014-present	Germany	D	A maximum of 2% hydrogen was blended with natural gas. There was no requirement of compressor since the hydrogen produced was at the same pressure as the gas distribution network.	2%	2%
11.	P2G Haßfurt	2016-present	Germany	D	The project has been operational since 2016 with positive news stories.	5%	5%
12.	Jupiter 1000	2017-present	France	T	Not Available	0%-6%	6%
13.	HyNTS Aberdeen Vision	2019-present	UK	D	No significant obstacles have been identified that would hinder the injection of 2% hydrogen into the national transmission system (NTS) at St Fergus and its distribution through the gas distribution network.	2%	2%
14.	Wind2Gas Brunsbuttel	2019-present	Germany	T	The hydrogen generated in the wind power-to-gas plant is compressed using two compressors and introduced into the high-pressure natural gas grid at a concentration of 2%.	2%	2%
15.	Snam Contursi Trial	2019-present	Italy	D	In 2019, Italy's gas utility, Snam, initiated a large-scale experiment by introducing 5% hydrogen into the Italian Gas Transmission Network. In December 2019, Snam doubled the concentration of hydrogen in the blend to 10%.	10%	10%
16.	Australian Hydrogen Centre	2019-present	Australia	D	The project commenced the delivery of a hydrogen blend, and could increase renewable hydrogen concentration up to 5% , through the existing natural gas infrastructure.	5%	NA
17.	Hy Deploy	2019-present	UK	D & E	Hy Deploy has successfully completed the demonstration of hydrogen blending up to 20 mol%. Study concludes that "Properly installed and maintained domestic appliances are safe with the blended gas".	20%	20%

T= Transmission
D=Distribution
E= End User
S= Storage

4.3 Stakeholder Consultations

Having conducted extensive literature reviews and scrutinized blending limits according to literature resources, this study now focuses on stakeholder consultations. The objective is to develop a comprehensive understanding of blending in the Indian context. Stakeholder consultations provide valuable insights, various viewpoints, and expert knowledge, especially relevant to promoting green hydrogen blended natural gas in India.

The insights gathered from engagement with stakeholders including **GAIL, PIL, NTPC & Gujarat Gas and Honeywell** have been explored in this section.

Stakeholder Consultation with GAIL

GAIL (India) Limited, in collaboration with EIL, conducted a comprehensive study on hydrogen (H2) blending in pipelines across various cities in India's City Gas Distribution (CGD) networks. Their research aimed to establish blending limits and assess infrastructure readiness for hydrogen incorporation. The study determined that for pipelines using X42 steel at approximately 19 bar pressure, the safe blending limit is 3%. However, components in lower distribution networks, such as GI piping and meters, can tolerate up to 10% H2 blending without significant operational issues. Pilot projects in Indore used MDPE pipelines, which tolerated up to 5% blending without adverse effects.

Separately, IOCL and IGL initiated the HCNG Project, testing up to 18% H2 blending in Delhi Transport Corporation (DTC) buses, with detailed results pending. Safety considerations highlighted potential fire hazards in confined spaces with H2-blended gas, though the risks were comparable to those from pure natural gas at 2% blending. The study underscores the need for tailored discussions with end-users, particularly power plants, to determine suitable blending limits for turbines and boilers.

Stakeholder Consultation with PIL

PIL's study on hydrogen blending in natural gas infrastructure examines a range of steel grades from API lower grades to X70 and is crucial for assessing feasibility and safety of using different types of steel under an operating pressure of 98 Bar. Blending limits are set at 5%-10%, with centrifugal compressors capped at 5% and gas turbines accommodating 5%-10%. The study focuses on core infrastructure components like pipelines, compressor stations, and turbines, but excludes end-users. The study identifies metallurgical issues beyond 5% blending and recommends pressure reduction as a risk mitigation strategy.

Stakeholder Consultation with Gujarat Gas

Gujarat Gas Limited achieved a significant milestone by successfully blending 5% hydrogen at NTPC Kawas Campus and obtained the approval to increase blending to 8%. NTPC initiated hydrogen integration through a global tender for "Building and Setup of Hydrogen Blending," collaborating with the private sector since September-October 2022. Key findings from the study confirm operational compatibility up to 8% blending without challenges at the NTPC canteen, validated by burner performance and odorizer efficacy at 5% hydrogen concentration. Precautions for steel components include corrosion mapping, with potential adjustments required for GI pipelines transmitting natural gas with more than 15% hydrogen blending. Customer feedback, predominantly positive, highlights satisfaction with flame behavior and color, but requests improvements in the emergency reporting system.

Stakeholder Consultation with Honeywell

Honeywell, a producer of meters and chromatographs, offered insights into gas metering and chromatography systems. Their Process Gas Chromatograph (PGC) retrofitting involves replacing carrier gas cylinders every 3 to 6 months, costing between Rs. 30,000 to 50,000 each. PGC models are available in single-stream and multiple-stream variants, with the latter being cost-effective for simultaneous measurement of multiple line compositions, while the primary expense lies in helium cylinders containing 99.99% pure helium. Honeywell's studies recommend injecting hydrogen from the bottom to prevent buoyancy issues and emphasizing the critical role of PGC installation at network junctures for accurate hydrogen composition analysis to avoid exceeding blending limits. Retrofitting from helium to argon cylinders involves straightforward procedures with shorter completion times, whereas extensive modifications requiring piping replacements demand longer service center or factory timelines.

Apart from these, a workshop was held in which GAIL, PESO and Gujarat Gas presented the results of the studies they conducted. Those results are included in the annexure.

5. Commercial Study

The commercial study calculates the cost implications of repurposing existing pipelines to accommodate hydrogen blending across different concentration levels, ranging from 0% to 20% viz. 0% to 2%, 2% to 5%, 5% to 10% and 10%-20%. It identifies specific components within the natural gas infrastructure that require replacement at each blending threshold, detailing retro fitment solutions and estimating the associated capital expenditure increases. The table presented below shows the retro fitment solution and anticipated capex.

Table 18: Retro fitment solution and Anticipated capex in Various Components

S.NO.	Element	Blending Limit (without modifications)	Retro fitment solution	Additional cost
1	Compressor (Gas Driven)	2%-5%	Possible solution for retrofit of compressor is replacing gas/IC engine drive with electrical drive.	6.5%-11% of Capex
2	Compressor (Electrically Driven)	15%-20%	Requires replacement	
3	Valve	10%	Requires replacement	
4	Gas Filter	10%	Requires replacement	
5	Fuel Filter	10%	Requires replacement	
6	Odorizer	15%	Requires replacement	
7	Insulation Joint	10%-20%		
8	Volumetric Meters	10%	Requires replacement	
9	Process gas chromatograph	<=0.2%	Replace helium cylinders with Argon Cylinder.	500 USD/Year/PGC
10	Gas Meters	10% - 50%		
11	Gas Turbine	1%-2%		10% of Capex
12	Feedstock/Reformer	2%	Deblending	INR 3.2/kg of Urea
13	Burner/Gas Stove	10%		
14	CNG Vehicle fuel Tank	2%	Deblending	5.2 Cr/CNG station
15	Condensing and Steam Boilers	5%-10%	Majority of cost increase coming from a burner suitable to fire hydrogen that produces low NOx emissions	35%-40% of Capex

The study calculates and compares the cost of transporting hydrogen by rail, road and pipelines for several ranges of distances and capacities. It infers road transport, offering flexibility and accessibility, to be the most efficient solution for smaller capacities and shorter distances. For capacities exceeding approximately 600-800 tons per day (TPD), pipeline transportation emerges as the preferred choice due to its efficiency and continuous delivery capabilities. The study notes that the lack of availability of suitable rail lines for transporting liquid hydrogen may limit the viability of rail in certain locations, although otherwise it is a feasible option for capacities upto ~600-800 TPD.

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5.1Cost of re-purposing existing NG Pipeline

In this section, a foundational methodology for determining the cost of repurposing existing natural gas (NG) pipelines is outlined. Based on the blending limit in various components, replacement list has been made which means components that needs to be retrofitted e.g., 0%-2% replacement list shows components that must be retrofitted while increasing the blending from 0% to 2%.

Cost Analysis-0%-2%

The cost analysis sections within this framework deals with the intricacies of the replacement list including the specific components involved. When transitioning from 0% to 2% blending, only two elements require repurposing: process gas chromatographs and gas turbines as shown in Table 7.1. But as per stakeholder consultations, gas turbines can tolerate up to 2%-5% hydrogen blending without the need of substantial modification. Hence, from 0%-2%, only process gas chromatographs must be replaced.

Table 19: Replacement List (0%-2%)

S.NO.	Element	Require changes
1	Compressor (Gas Driven)	No
2	Compressor (Electrically Driven)	No
3	Valve	No
4	Gas Filter	No
5	Fuel Filter	No
6	Odorizer/Odorant	No
7	Insulation Joint	No
8	Volumetric Meters	No
9	**Process gas chromatograph**	**Yes**
10	Gas Meters	No
11	Gas Turbine	No
12	Feedstock/Reformer	No
13	Burner/Gas Stove	No
14	CNG Vehicle fuel Tank	No
15	Gas regulator	No

Process gas chromatograph presents a unique challenge due to its lower blending limit, primarily stemming from the presence of helium as a carrier gas. Helium's thermal conductivity value closely resembles that of hydrogen, rendering accurate detection challenging.
To mitigate this issue, a shift from helium to argon cylinders is imperative. Through consultations with industry experts such as Honeywell, it has been ascertained that the cost of one argon cylinder ranges from Rs. 30,000 INR to Rs. 50,000 INR, with a lifespan of one year. This translates to an additional cost of approximately 500 USD per year. When juxtaposed with the average capital expenditure (CAPEX) of a process gas chromatograph, estimated at 40,000-50,000 USD (approx. 2500 USD/year to 3500 USD/year) the incremental cost increase stands at approximately ~14%-20%. (Honeywell, n.d.)(Figure shown below serves as a visual aid, delineating the methodology employed for estimating costs within this framework.

Figure 18: Cost implication of retrofitting PGC.

S.No	Equipment	Existing Cost Scenario	Retrofitting Solution	Retrofitting Cost	Increase in Capex
1	PGC	40000-50000 USD Annual Cost= 2500-3500 USD/Year	Replace helium cylinders with Argon Cylinder. Argon Cylinder INR 30,000 to 50,000 and its life is 1 year.(Honeywell Estimates)	500 USD/Year	~14%-20%

Cost Analysis-2%-5%

The cost analysis sections within this framework delve into the intricacies of the replacement list and subsequently delve into the specific components involved. When transitioning from 2% to 5% blending, four elements necessitate repurposing: process gas chromatographs, gas turbines, Feedstock equipment and CNG Vehicle fuel Tank and compressor as shown in Table below apart from process gas chromatograph. While moving from 2% to 5%, gas chromatographs would have been already replaced hence focus will be on feedstock applications, gas turbines, CNG Fuel Tank and compressor.

Table 20: Replacement List (2%-5%)

S.NO.	Element	To be retrofitted or not
1	**Compressor (Gas Driven)**	**Yes**
2	Compressor (Electrically Driven)	No
3	Valve	No
4	Gas Filter	No
5	Fuel Filter	No
6	Odorizer/Odorant	No
7	Insulation Joint	No
8	Volumetric Meters	No
9	**Process gas chromatograph**	**Yes**
10	Gas Meters	No
11	**Gas Turbine**	**Yes**
12	**Feedstock/Reformer**	**Yes**
13	Burner/Gas Stove	No
14	**CNG Vehicle fuel Tank**	**Yes**
15	Gas regulator	No

In the context of feedstock applications and CNG fuel tanks, the primary challenge lies in de-blending hydrogen from the blended gas stream. Various methods exist for de-blending, including Pressure Swing Adsorption (PSA), membrane separation, and Electrochemical Hydrogen Separation. While membrane separation and electrochemical hydrogen separation are still in the laboratory phase, PSA stands out as the mature technology currently available for large-scale implementation.

The cost associated with de-blending through PSA at a large scale is approximately 1.5 USD per kilogram of hydrogen extracted. To assess the cost implications of these de-blending technologies in both feedstock and CNG applications, two distinct scenarios have been considered:

Feedstock Application: For this case, the fertilizer plant example serves as a representative example. A sample fertilizer plant produces approximately 35.68 lakhs metric tons of urea annually (only a representative case), requiring around 9.51 lakhs metric tons of Natural gas based on mole analysis. If a 10% blending is done, then hydrogen required will be approx. 0.96 lakhs metric tons. Considering de-blending cost as 1.5 USD/kg, Cost increment introduced via de-blending on per kg of urea production will be 3.20 INR.

The table shown below provides a comprehensive assessment of the cost implications in the feedstock application in fertilizer plants.

Table 21: De-blending Impact on a sample fertilizer plant.

Feedstock- A specific Fertilizer Company			
S.NO.	**Particular**	**Value**	**Limit**
1	Total Capacity	35.68	LMT of Urea
2	NG Required	9.51	LMT
3	H2 Capacity (10% Blending)	0.95	LMT
4	De-blending Cost	1.5	USD/kg
5	**Cost Increment per kg of Urea**	**3.20**	**INR/kg**

CNG Station:

In CNG (Compressed Natural Gas) stations, hydrogen blending requires a substantial financial investment. For a CNG station with a daily capacity of 4,000 kilograms, 10% hydrogen blending costs approximately 1.75

crores, which is a significant financial commitment for integrating hydrogen blending into the CNG infrastructure. The figure below shows a detailed analysis of the cost considerations involved in implementing hydrogen blending at CNG stations.

Figure 19: De-blending impact on CNG Station

CNG Station			
S.NO.	**Particular**	**Value**	**Unit**
1	NG Capacity	4000	kg/day
2	H2 Capacity(10% Blending)	400	kg/day
3	De-Blending Cost	1.5	USD/kg
4	**Total Cost of De-blending(Annual)**	**1.75**	**INR Crores**

Assuming a price of 74.09 INR/kg for Compressed Natural Gas (CNG), which is equivalent to 17.99 USD/MMBtu (MMBTU is million British thermal units), blending 10% Hydrogen (H_2) into CNG, raises the price to 18.67 USD/MMBtu. However, upon de-blending the hydrogen, the resulting CNG price further escalates to 21.28 USD/MMBtu.

Gas Turbines

Enabling gas turbines to accommodate higher blending limits of 15% requires upgrading the combustion system, instrumentation, electrical equipment, and fuel blending mechanisms, which increases the capital expenditure (CAPEX) associated with the turbines by approximately 10%.
Gas turbines with an average CAPEX of around 1100-2400 USD per kilowatt (kW) would therefore undergo this upgrade at an estimated cost of 110-240 USD per kW. This investment is vital to ensure the turbines' ability to effectively utilize fuel blends. The figure below shows the cost of retrofitting a gas turbine.

Figure 20: Cost implication of retrofitting Gas Turbine

S.No	Equipment	Existing Cost Scenario	Retrofitting Solution	Retrofitting Cost	Increase in Capex
2	**Gas Turbine**	1100-2400 USD/ kW {According to literature review, cost came out to be 1100-2400 USD/ kW, while it was 1100 USD/ kW as per stakeholders}	Upgrade to combustion system and controls. Instrumentation and electrical equipment upgrade along with fuel blending Skid	110-240 USD/ kW {It takes around 10% of capex to retrofit turbine, in order to make it accommodate 15% blending. }	~ 10%

Compressor

Hydrogen blending in gas compressors is limited by the compressor drive system, which typically has a low blending limit of around 3% to 5%. While compressors themselves can generally handle up to 20% hydrogen blending, the restrictions imposed by the compressor drive necessitate retrofitting.
One viable solution for retrofitting compressors to accommodate higher hydrogen blending ratios, is replacing the existing gas or internal combustion (IC) engine drive with an electrical drive system. This allows for greater flexibility and compatibility with higher hydrogen concentrations. However, it's essential to recognize that the retrofit process may entail additional modifications beyond simply swapping out the drive system. Depending on the specific circumstances, the compressor impeller may need to be changed to ensure optimal performance and efficiency under the new operating conditions. Additionally, the adjustments to the compressor's operating parameters may be necessary to optimize performance and maintain reliability. Typically, the average cost of a compressor is approximately 30,000 USD per kilowatt (kW), while the average cost of an electrical drive system amounts to around 2400 USD per kW. This adds up to an estimated average additional CAPEX of around 8%. The figure below shows the range of capex and the increase in capex.

.((Aziaka D.S, n.d.) It means estimated additional CAPEX of around 8%(Average)as shown in figure below. The figure presented below shows the range of capex and increase in capex.

Figure 21: Cost implication of retrofitting Compressor.

S.No	Equipment	Existing Cost Scenario	Retrofitting Solution	Retrofitting Cost	Increase in Capex
5	Compressor	20000-40000 USD/ kW	Possible solution for retrofit of compressor is replacing gas/IC engine drive with electrical drive.	2200-2600 USD/ kW	6.5%- 11%

Cost Analysis-5%-10%

The cost analysis sections within this framework delve into the intricacies of the replacement list and subsequently delve into the specific components involved. When transitioning from 5% to 10% blending, various elements necessitate repurposing: process gas chromatographs, gas turbines, Feedstock equipment, CNG Vehicle fuel Tank and compressor as shown in Table shown below. While moving from 2% to 10%, all these components would have been replaced except the gas regulator so this section would focus on gas regulator.

Table 22: Replacement Cost (5%-10%)

S.NO.	Element	To be retrofitted or not
1	**Compressor (Gas Driven)**	**Yes**
2	Compressor (Electrically Driven)	No
3	Valve	No
4	Gas Filter	No
5	Fuel Filter	No
6	Odorizer/Odorant	No
7	Insulation Joint	No
8	Volumetric Meters	No
9	**Process gas chromatograph**	**Yes**
10	Gas Meters	No
11	**Gas Turbine**	**Yes**
12	**Feedstock/Reformer**	**Yes**
13	Burner/Gas Stove	No
14	**CNG Vehicle fuel Tank**	**Yes**
15	**Gas regulator**	**Yes**

Cost Analysis-10%-20%

The cost analysis sections within this framework delve into the intricacies of the replacement list and subsequently delve into the specific components involved. When transitioning from 10% to 20% blending, almost all elements require retro fitment as shown in Table presented below.

Table 23: Replacement List (10%-20%)

S.NO.	Element	To be retrofitted or Not
1	**Compressor (Gas Driven)**	**Yes**
2	**Compressor (Electrically Driven)**	**Yes**
3	**Valve**	**Yes**
4	**Gas Filter**	**Yes**
5	**Fuel Filter**	**Yes**
6	**Odorizer/Odorant**	**Yes**
7	**Insulation Joint**	**Yes**

8	**Volumetric Meters**	**Yes**
9	**Process gas chromatograph**	**Yes**
10	**Gas Meters**	**Yes**
11	**Gas Turbine**	**Yes**
12	**Feedstock/Reformer**	**Yes**
13	**Burner/Gas Stove**	**Yes**
14	**CNG Vehicle fuel Tank**	**Yes**
15	**Gas regulator**	**Yes**

Valves, meters, filters, and boilers require replacement, with the exception of components already upgraded during the transition from 5% to 10% blending.
In the case of boilers, a strategy to render them "H2 ready" is feasible. This involves replacing certain components to ensure compatibility with hydrogen fuel. Specifically, valves, filters, and meters must be replaced with counterparts designed for hydrogen applications. However, boilers can be adapted to accommodate hydrogen without complete replacement, mainly by integrating burners capable of firing hydrogen efficiently while minimizing emissions of nitrogen oxides (NOx). These burners, along with modifications to burner control systems to accommodate the differing physical properties of hydrogen and natural gas, account for the majority of the costs associated with making boilers hydrogen-ready. Making boilers hydrogen-ready is estimated to result in a capital expenditure (CAPEX) increase of approximately 35%-40%, as depicted in the table below

Table 24: Cost implications of retrofitting Boiler. (kiwa, n.d.)

S.NO.	Particular	Value	Unit
1	Cost of 5 MW Conventional Boiler	~1,65,000-2,00,000	USD
2	Conversion Cost of conventional to hydrogen-ready	~65,000-70,000	USD
3	**Increase in Capex**	**35%-40%**	**%**

Retrofitting or modification to make the odorizer hydrogen ready is very costly, so it is better to replace it altogether.

The re-purposing of existing natural gas pipelines to facilitate the transportation of pure hydrogen presents both a significant opportunity and a considerable challenge for energy infrastructure development. Estimates indicate that repurposing these pipelines would cost €0.2 million to €0.6 million per kilometer, demonstrating the substantial financial investment required for such endeavors. Moreover, the process of making natural gas pipelines "hydrogen ready" entails additional costs, typically ranging from 10% to 50% of the expenses incurred in constructing new hydrogen pipelines. On average, this translates to approximately 23% of the cost of new hydrogen pipeline construction.

These figures underscore the complexities and costs involved in adapting existing infrastructure to accommodate hydrogen. Despite the financial implications, repurposing natural gas pipelines offers a comparatively cost-effective and efficient means of leveraging existing infrastructure to support hydrogen transportation, thereby facilitating the widespread adoption of hydrogen as a clean energy alternative.

5.2Economic Analysis of new and hydrogen ready pipelines

In the preceding sections, various types of pipelines, transmission lines, distribution lines and service lines have been discussed. This section will focus on the capital expenditure (capex) and operational expenditure (opex) of hydrogen ready pipelines. The table below presents the basic assumptions of the economic model.

Table 25: Basic outlines of model building.

1	Capex and Opex	The capital expenditure (Capex) and operational expenditure (Opex) for the new hydrogen pipeline have been assessed using the **Hydrogen Delivery Scenario Analysis Model (HDSAM),** a tool developed by Argonne National Laboratory in the United States.
2	Accuracy	The Major Reason to rely on such Model is that currently all capex and models available for India, are dedicated to Natural gas. NG models cannot be accurately applied to hydrogen because of various complex scenarios viz. embrittlement, safety scenarios.
3	Customization to Indian Context	Approach will be to calculate cost on basis of **HDSAM model** then adjust it to Indian perspective by using **purchasing power parity/Other Suitable Factors and Exchange Rate.**

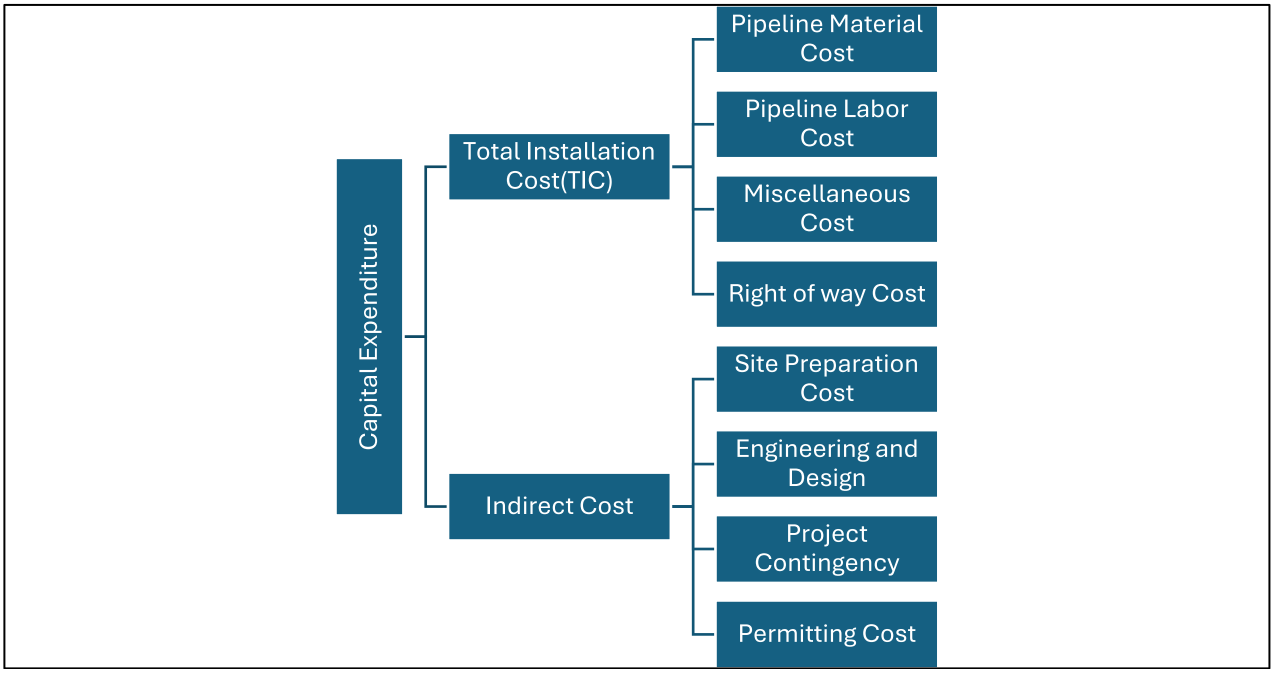
In this analysis, the pipeline system is considered to comprise three primary components: Transmission Lines, Distribution Lines, and Service Lines. The assessment covers both capital expenditure (CAPEX) and operational expenditure (OPEX) associated with each category. Furthermore, a brief exploration of technical parameters is undertaken, with a primary focus on the Transmission Line. Importantly, the cost of compressor stations is integrated into the CAPEX Transmission Pipeline infrastructure, while no such allocation is made for Distribution and Service Lines.

Capital Expenditure

The method elucidated in this section is consistently employed to evaluate the cost of the transmission pipeline, distribution lines, and service lines.

Capital expenditure (CAPEX) encompasses the financial investments made for the construction of the pipeline infrastructure. This expenditure includes costs associated with laying down new pipeline sections, installing pumping or compressor stations, and acquiring necessary land rights or permits. CAPEX can ensure the reliability, safety, and efficiency of the pipeline network, by enabling the development of robust and modern infrastructure capable of meeting current and future demands for transportation of fluids or gases.
Pipeline systems consist of several key components essential for their safe and efficient operation. At the core are the pipes themselves, typically constructed from steel or plastic and varying in diameter and length based on the volume and characteristics of the material being transported. Additionally, to maintain the required pressure along the route, pumping and compressor stations are required for liquid and gas pipelines, respectively. Valves are strategically placed along the pipeline to regulate flow, facilitate maintenance, and enable emergency shutdowns when necessary. Metering and monitoring equipment are installed to accurately measure flow rate, pressure, temperature, and other critical parameters for operational control and regulatory compliance. Hence, to accurately determine pipeline capex, a bottom-up analysis is required. The figure below shows the bottom-up analysis of the capex component.

Figure 22: Capital Cost Bifurcation



Following the delineation of these CAPEX components, it becomes imperative to elucidate and comprehend them thoroughly. This entails providing clear definitions of the various components and elucidating the types of costs they encompass. The table presented below shows the definition of various capex components.

Table 26: Cost components Elaboration

S.NO.	Particular	Explanation
1.	Pipeline Material Cost	Cost incurred for procuring pipe spools for the required length.
2.	Pipeline Labor Cost	Manpower Cost associated with excavation, laying of pipeline, backfilling and then commissioning.
3.	Miscellaneous Cost	Cost incurred for procuring ancillary equipment e.g., Pipeline internal and external coating, Valves, Gas meters, process gas chromatographs, gas analyzers etc.
4.	Right of Way Cost	Cost associated with land acquisition.
5.	Site Preparation Cost	Cost associated with grading and excavation of the site; installation and hookup of electrical, water, and sewer systems; and construction of all internal roads, walkways, and parking lots.
6.	Engineering and Design Cost	It includes salaries and overhead for the engineering, drafting, and project management personnel on the project.
7.	Project Contingency	It is a factor to cover unforeseen circumstances, including project risks or uncertainties). These may include loss of time due to storms and strikes, small changes in the design etc.
8.	Permitting	The permitting costs are costs borne by the facilities to obtain the necessary approvals to design and install the control equipment. This is a site-specific cost.

Following the clear definition of various components, it is essential to examine the equations utilized in the evaluation of CAPEX for the components. Initially, the pipeline material cost, labor cost, and miscellaneous expenses are determined employing HDSAM Model. Subsequently, the Right of Way (ROW) cost is estimated. This involves calculating expenses for securing the necessary land rights and easements for the pipeline route. The table below presents the equations employed to evaluate these costs, accompanied by their respective sources.

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Table 27: Equations used to evaluate capex. (Mohd Adnan Khan, n.d.)

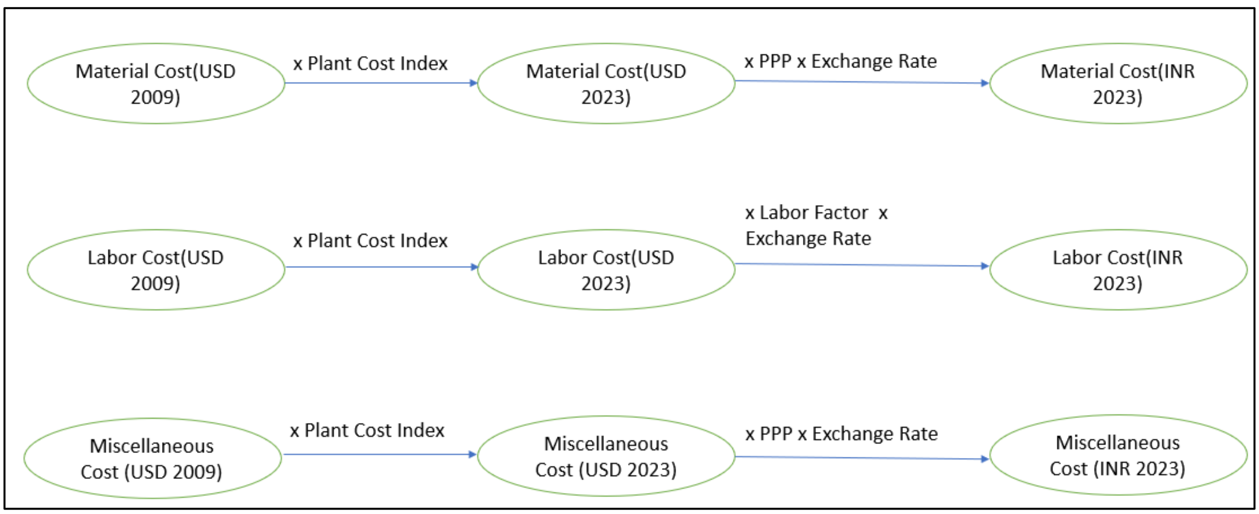
S.NO.	Particular	Equation Employed	Unit	Source
1	Pipeline Material Cost	1.1 * 63027*exp (Diameter, in.*0.0697) * (Length, miles)	USD (2009)	HDSAM Model

2	Pipeline Labor Cost	1.1 * ([-51.393 * (Diameter, in.)^2 + 43,523 * (Diameter, in.) + 16,171] * (Length, miles))	USD (2009)	HDSAM Model
3	Miscellaneous Cost	1.1 * ([303.13 * (Diameter, in.)^2 + 12,908 * (Diameter, in.) + 123,245] * (Length, miles))	USD (2009)	HDSAM Model
4	Right of Way Cost	50% of Land Cost. Land Cost= Land area (Length*20 meters) * Land Price	INR (2023)	Secondary Research

The HDSAM model evaluates costs in USD 2009, so the results need to be converted to INR 2023 for current application in India. This conversion process involves several steps to ensure accuracy and relevance. Firstly, costs calculated in USD 2009 are adjusted to USD 2023 using the Plant Cost Index, which reflects the evolution of capital expenditure from the past to the present. Subsequently, these costs are adapted to the Indian context by multiplying them by the 2023 Purchasing Power Parity (PPP) and the exchange rate. PPP accounts for differences in the cost of living between countries, thereby adjusting the costs to reflect purchasing power in India.

Moreover, in the case of labor costs, a labor factor is utilized instead of PPP. This factor is the ratio of the minimum wage in India to the minimum wage in the USA, specifically for labor working on infrastructure projects. This approach ensures that labor costs are tailored to the local labor market conditions and wage standards, enhancing the accuracy of the overall cost estimation process. By converting costs to the Indian context in this manner, the evaluation of CAPEX components becomes more relevant and insightful for decision-making within the Indian pipeline project landscape. The figure below presents the summary of these conversions.

Figure 23: Adjusting USD (2009) to Indian Context



After determining the four costs, namely Material Cost, Labor Cost, Miscellaneous Cost, and Right of Way Costs, they are summed up to calculate the overall cost of installing the pipeline infrastructure..

Total Installation Cost (TIC) = Material Cost + Labor Cost + Miscellaneous Cost + Right of way Cost

After determining the Total Installation Cost, the evaluation proceeds to assess the Indirect Cost, comprising several key components. These include Site Preparation Cost, Engineering and Design Cost, Project Contingency, and Permitting Cost. Indirect costs typically account for approximately 28% of the Total Installation Cost and play a significant role in the overall project budget. Site Preparation Cost encompasses expenses related to clearing and preparing the construction site, ensuring it is conducive to the pipeline installation process.

Indirect Cost = Site preparation Cost + Engineering & Design Cost + Project Contingency Cost + Permitting Cost = 28% of Total Installation Cost

These indirect costs collectively contribute to the overall financial outlay of the project and are essential for its successful execution. A detailed breakdown of these indirect costs is provided in Table presented below.

Table 28: Indirect Cost breakdown (Mohd Adnan Khan, n.d.)

S.NO.	Particular	Weightage	Reference
1	Site preparation	5%	% of Total Installation Cost
2	Engineering & Design	10%	% of Total Installation Cost
3	Project Contingency	10%	% of Total Installation Cost
4	Permitting	3%	% of Total Installation Cost

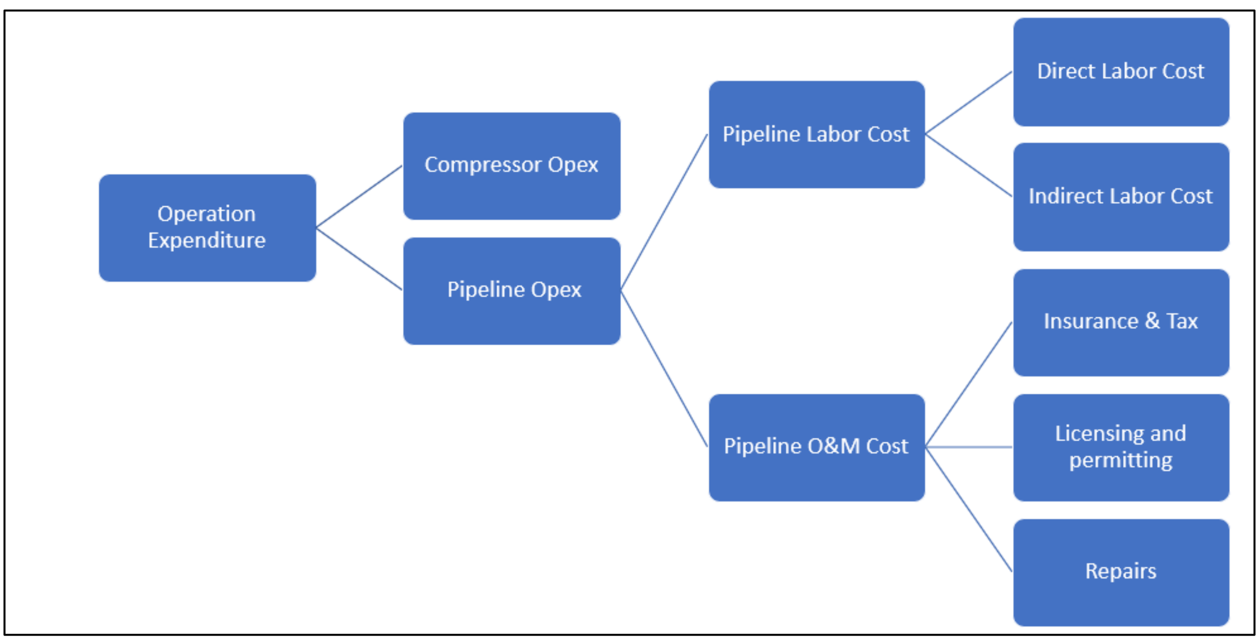
Once total installation costs and indirect costs are evaluated then Total capex is found by equations written depending upon type of pipeline. Compressor capex is evaluated in the Compressor analysis section.
Capital Expenditure = Total Installation Cost + Indirect Cost (For Distribution line and service line)
Capital Expenditure = Total Installation Cost + Indirect Cost + Compressor Cost (Transmission Line)

Operation expenditure

Operational expenditure (OPEX) of a pipeline encompasses the ongoing costs associated with the maintenance, operation, and management of the pipeline system throughout its lifecycle. These expenses are recurrent and typically include various elements such as labor, maintenance, repairs, inspections, regulatory compliance, energy consumption, and administrative overhead. Labor costs encompass salaries and wages for personnel involved in pipeline operation, maintenance, and monitoring activities. Maintenance and repair costs cover expenses related to routine upkeep, equipment servicing, and emergency repairs to ensure the integrity and reliability of the pipeline infrastructure.

Inspection costs involve periodic assessments and testing to detect potential issues and ensure compliance with safety and environmental regulations. Regulatory compliance costs include fees, permits, and compliance efforts necessary to adhere to government regulations and industry standards. Figure presented belowshows the bottom-up analysis of opex evaluation of a pipeline.

Figure 24: Operation expenditure Breakdown



The operational expenditure (OPEX) associated with compressor operations is straightforwardly determined as 4% of the compressor capital expenditure (CAPEX). This assessment method provides a clear estimation of the ongoing costs required for the maintenance and operation of compressor stations within the pipeline network. Additionally, the labor costs related to pipeline operations consist of both direct and indirect labor expenses. Table 28 outlines the equations utilized to calculate these labor costs, incorporating factors such as wages, hours worked, and labor efficiency rates to derive accurate estimations.

Once the compressor OPEX and pipeline labor costs are determined, the pipeline operation and maintenance (O&M) costs are evaluated by calculating a percentage of the total installation cost. This approach allows for a comprehensive assessment of the ongoing expenses required to ensure the efficient and reliable functioning of the pipeline system. Table 29shown below provides a breakdown of the components comprising the pipeline O&M costs.

Table 29: Labor Cost and compressor cost breakdown (Mohd Adnan Khan, n.d.)

S. No.	Particular	Equation
1	Compressor Opex	4% of compressor capex
2	Direct Labor Cost	8320 * (Average pipeline use (kg H2/day)/100000)$^{0.25}$* Labor rate (INR/hour)
3	Indirect Labor Cost	Direct Labor Cost * Indirect labour Factor (50%)

Table 30: Pipeline O&M Cost (Mohd Adnan Khan, n.d.)

Pipeline O&M Cost			
S. No.	Particular	Share	Reference
1	Insurance	1%	% of Total Installation Cost
2	Property Tax	1%	% of Total Installation Cost
3	Licensing and permitting	0.10%	% of Total Installation Cost
4	O&M and repairs	0.10%	% of Total Installation Cost

➢ Sensitivity Analysis

This section assesses both the capital expenditure (CAPEX) and the operational expenditure (OPEX) pertaining to transmission, distribution, and service lines. The results presented in the Table below, list the expenses incurred on these critical components of infrastructure development.

Table 31: Capex and Opex of Sample Case

S.NO.	Particular	Diameter(mm)	Length(km)	Capex	Opex	Unit
1	Transmission Line	800	300	~1707	~35	INR Crores
2	Distribution Line	100	100	~85	~1-2	INR Crores
3	Service Line	40	100	~63	~1	INR Crores

This analysis aims to discern how variations in the parameters of transmission lines, specifically diameter (mm) and length (km), influence the associated CAPEX (CAPEX is in INR Crores). The outcomes of this sensitivity analysis are meticulously documented in Table 31, which serves as a pivotal reference point for understanding the nuanced relationship between these parameters and the resultant CAPEX implications. One Column shows the cost of pipeline for a particular length of various diameters.

Table 32: Sensitivity Analysis (CAPEX is in INR Crores)

		Length of Pipeline (in km)									
		50	100	150	200	250	300	350	400	450	500
Diameter of Pipeline(mm)	**300**	167	210	294	378	462	547	631	715	799	884
	350	179	275	330	426	522	618	714	810	906	1002
	400	233	300	409	517	626	693	802	911	1020	1128
	450	287	368	449	571	693	815	937	1059	1181	1261
	500	343	396	532	669	763	899	1036	1172	1308	1444
	550	399	468	619	729	880	1031	1182	1292	1443	1594

	600	456	541	667	834	960	1127	1294	1461	1628	1796
	650	556	616	759	944	1086	1271	1455	1598	1782	1966
	700	616	694	855	1017	1219	1422	1583	1785	1988	2191
	750	718	816	956	1136	1359	1539	1762	1984	2164	2387
	800	822	900	1102	1262	1505	1707	1951	2152	2396	2639
	850	968	1028	1211	1436	1660	1885	2151	2376	2642	2908
	900	1076	1160	1326	1576	1825	2074	2365	2614	2905	3154
	950	1226	1296	1489	1724	2000	2276	2593	2869	3187	3463
	1000	1379	1436	1659	1923	2228	2533	2838	3143	3490	3795
	1050	1576	1583	1837	2132	2428	2765	3102	3439	3817	4154
	1100	1735	1776	2024	2313	2685	3015	3428	3800	4171	4584
	1150	1938	1976	2221	2548	2917	3327	3737	4147	4556	5008
	1200	2146	2185	2430	2799	3210	3662	4114	4566	5018	5470
	1250	2399	2402	2693	3109	3525	4024	4481	4979	5478	5976
	1300	2616	2629	2972	3398	3865	4374	4924	5474	6024	6574
	1350	2879	2908	3268	3710	4276	4800	5408	6015	6581	7229
	1400	3191	3160	3583	4089	4677	5307	5937	6566	7237	7908
	1450	3469	3467	3920	4497	5116	5817	6518	7219	7961	8703
	1500	3796	3792	4284	4940	5638	6378	7158	7939	8761	9583

5.3Hydrogen Transportation by Road and Railways

In addition to pipelines, hydrogen can also be transported by rail and road. By road, there are two primary methods: transporting compressed hydrogen in gaseous form using tube trailers and transporting liquid hydrogen using liquid trailers. Liquid hydrogen can also be transported by rail, but transporting compressed hydrogen gas by rail is not economically feasible.

Transportation by Road

1. **Compressed Hydrogen by Tube Trailer: Compressed Hydrogen by Tube Trailer:** In this case, first of all, capital expenditure (capex) is evaluated. The capex refers to the cost of trucks required to transport a given volume of gas. The cost of a single truck is calculated by summing the costs of the tube trailer, truck undercarriage, and truck cab. Next, the number of trucks needed to transport a given volume is determined based on factors such as truck speed, loading and unloading times, and the number of trips required to transport the specified volume over the given distance in a given time. Following this, operating expenditure (opex) is evaluated. Opex includes the fuel cost, which is determined by the distance traveled and the truck's mileage as well as the driver's salary. The annual cost is subsequently calculated by summing the amortized capex and the opex. Finally, the total cost is divided by the volume transported to evaluate the transportation cost per unit of volume.

2. **Liquid hydrogen by Liquid Trailer:** Capital expenditure (capex) is assessed for acquiring trucks needed to transport a specified volume of gas. The cost of a single truck is computed by adding the expenses for the liquid trailer, truck undercarriage, and truck cab. Subsequently, the requisite number of trucks needed for transporting the specified volume is determined, considering factors such as truck speed, loading and unloading times, and the number of trips required per truck to transport the specified volume over the given distance in a given time. Following the evaluation of capex, operational expenditure (opex) is considered. Opex comprises of fuel costs determined by the distance traveled

by each truck and its mileage as well as driver expenses. The annual cost is calculated by summing up the amortized capex and opex expenses. Finally, the total cost is divided by the volume of gas transported to ascertain the transportation cost per unit volume. This procedure closely mirrors the one used for compressed hydrogen, except a liquid trailer replaces the tube trailer.

The tables below list the Capex and opex assumptions in case of transportation of compressed and liquid hydrogen by road.

Table 33: Capex Assumptions- Hydrogen transportation by Road

S.NO.	Particular	Unit	Value
1	Total Single Truck Cost-Compressed H2	INR Crores	~6-7
2	Total Single Truck Cost-Liquid H2	INR Crores	~6

Table 34: Opex Assumptions- Hydrogen transportation by Road

S.NO.	Particular	Unit	Value
1	Capacity of 1 Tube Trailer Truck-Compressed H2	kg	380
2	Capacity of Liquid Trailer	kg	4000
2	Truck Speed	km/h	24
4	Truck loading/unloading time	h	2
5	Mileage of Trucks	km/liters	3
6	Diesel Cost	INR/liter	89
7	Number of Person per truck	Number	2
8	Driver Salary per month	INR	20000

Transportation by Rail

Rail units are the key component of capital expenditure (capex) for transportation of liquid hydrogen by rail. Capex costs are solely determined by the procurement expenses for these units. The evaluation of operational expenditure (opex) is straightforward, due to the availability of the Indian Railways' liquid chemical container facility, where charges are determined based on the distance traveled. Hence, opex is essentially the freight cost incurred. Following this, capex costs are amortized and combined with opex to determine the total annual cost. Subsequently, this total cost is divided by the volume of liquid hydrogen transported to ascertain the transportation cost per unit volume. The table presented below outlines the assumptions regarding capex and opex

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Table 35: Capex Assumptions- Hydrogen transportation by Rail

S.NO.	Particular	Unit	Value
1	Total Single Rail Unit Cost (Single Bogey Cost)	INR Crores	6.37

Table 36: Opex Assumptions- Hydrogen transportation by Rail

S.NO.	Particular	Unit	Value
1	Capacity of Single Rail Unit	kg	9000
2	Rail loading/unloading time	h	12
3	Rail Freight Charges	INR/Ton/km	2.45

For a comprehensive understanding of hydrogen transportation by various means—namely, pipeline, rail, and road— it is essential to compare the costs associated with each mode over varying distances and capacities. This evaluation is crucial for determining the optimal transportation method under different capacity and distance scenarios. Three graphs have been plotted to illustrate the relative costs of different modes of hydrogen transportation over a range of distances of 100 km, 500 km, and 1000 km.

The analysis considers four transportation modes: Pipeline, Road (Compressed Hydrogen), Road (Liquid Hydrogen), and Rail Transportation.

Figure 25: H2 transportation for 100km

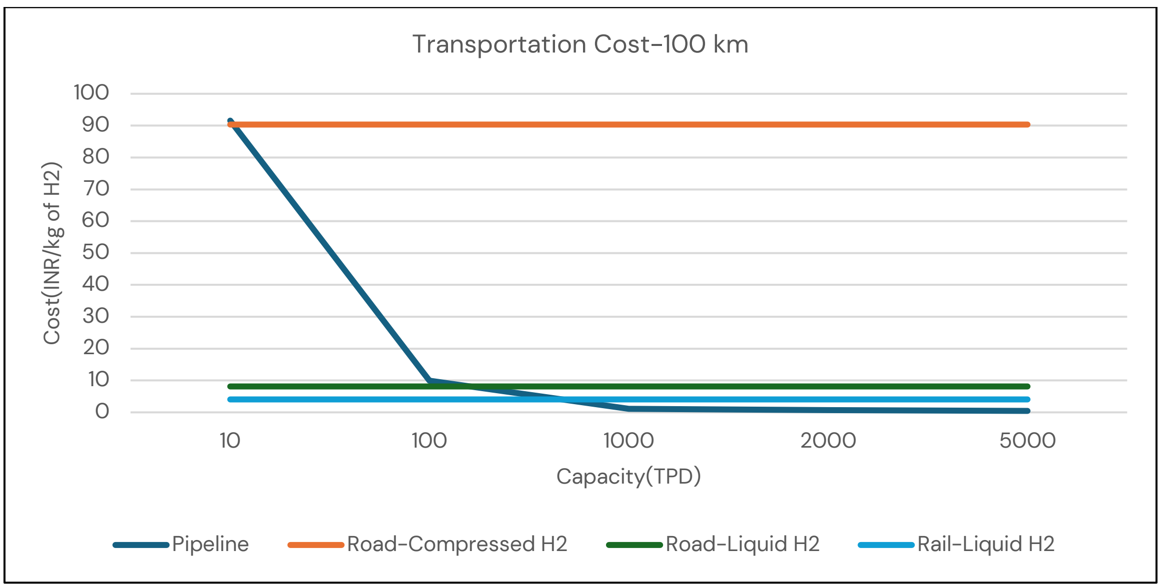


Figure 26: H2 transportation for 500km

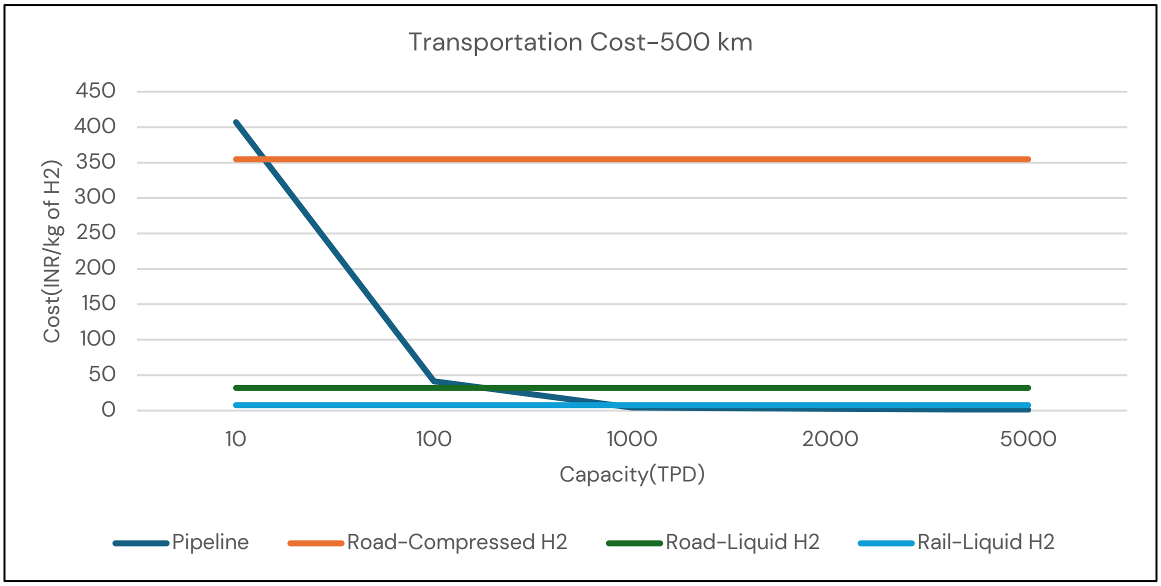
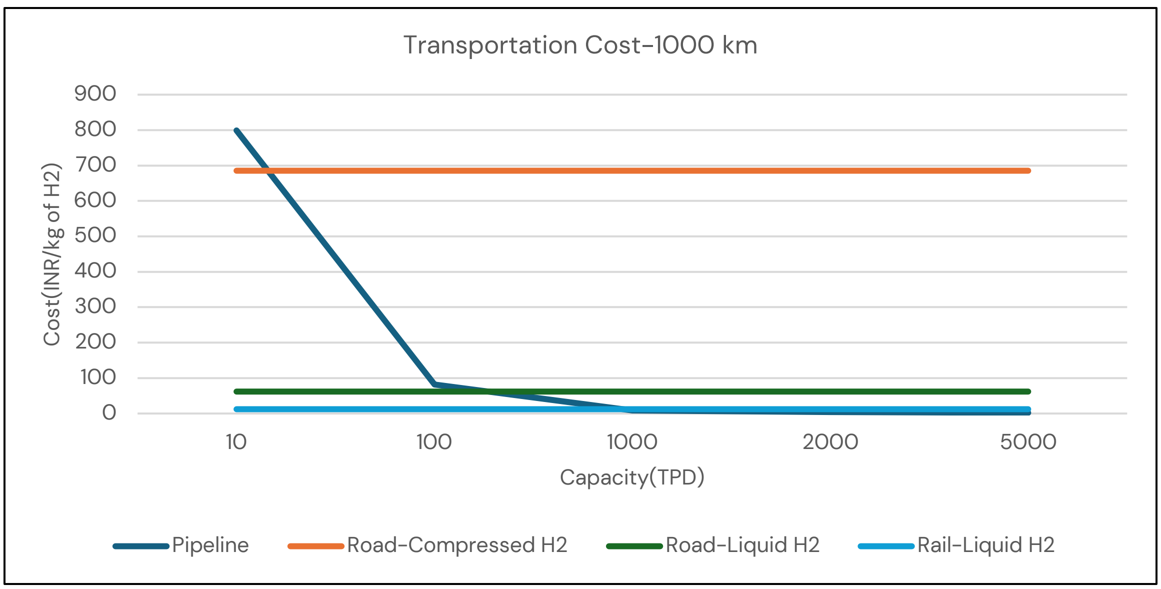


Figure 27: H2 transportation for 1000km



Upon comparing the various costs of different transportation modes, it is observed that for capacities up to approximately 600-800 tons per day (TPD), transporting hydrogen by rail in its liquid form is the most viable option, although the availability of rail lines at every location may limit its practicality. Transportation by road, specifically using compressed hydrogen, is generally the least viable option; however, for low capacities ranging from about 1 to 10 TPD and short distances, this method may be preferred due to its flexibility and accessibility. For capacities greater than approximately 600-800 TPD, transporting hydrogen via pipeline is the most desirable option, offering a cost-effective and efficient solution, provided the necessary infrastructure is in place.

5.4Business Models

- **Demand uncertainties** - Green hydrogen is an evolving industry, and there is significant demand uncertainty. The high cost of low-carbon green hydrogen raises questions about who should bear the financial burden. The viability of long-term demand is also uncertain, compounded by the high capital expenditure required for end users to adopt hydrogen technologies. Thus, enforcing mandates for key consuming industries such as refineries is one way to expand the baseline demand for hydrogen.
- **Cost uncertainties** – The fast-evolving technology landscape and reducing price curve mean that newer technologies could potentially offer lower prices, creating volatility and unpredictability in the market.
- **Infrastructure uncertainties**- Uncertainty about the nature of future hydrogen infrastructure, blended or pure, makes it difficult to plan and invest.
- **Regulatory uncertainties** complicate the development of hydrogen infrastructure. Identifying the nodal agencies responsible for developing hydrogen regulations and understanding the impact of regulatory changes, such as subsidies, are critical issues that need to be addressed

In terms of business models, it is essential to consider innovative approaches that can accommodate these uncertainties and provide a sustainable path forward. Key

Table 37 outlines a few potential business models designed to manage uncertainties in the growth of hydrogen infrastructure.

Table 37: Potential Business models for managing uncertainties

Potential business models	Key elements	Potential end user segments	Key uncertainties managed
Development of locally distributed pure hydrogen network through anchor customers such as refineries and ammonia	• Refineries/non urea ammonia plants provide anchor load on take or pay basis or BOO basis with support from government under SIGHT scheme (Tranche 2A and Tranche 2B) • Additionally green hydrogen production may be marketed to nearby small industries such as chemicals, other small industries etc. • Marketing to these small industries may be on commodity link or fixed price basis and thus economies of scale could be brough in	Refineries Steel plants Ammonia plants	Demand uncertainty. Cost uncertainty Infrastructure uncertainty
Blended H2 with differential cost	• Mandate for blended hydrogen in CGD sector • Take or pay contract linked to current RLNG prices, with a small premium for hydrogen blending. • Additional infrastructure changes for blending supported through VGF funding or city gas distribution companies • Uncertainties managed by CGD companies for its industrial, domestic or commercial users. • At small blending percentage, there will be limited cost impact	Small industries CGD network	Demand uncertainty. Cost uncertainty

6. Regulatory Study

This study assesses existing regulatory gaps that may hinder the transition to green hydrogen and meticulously identifies the measures that need to be implemented throughout the entire low-carbon hydrogen value chain. The findings of this study will pave the way for a comprehensive regulatory roadmap towards a green hydrogen-powered future for India.

This section focuses on the following areas-

- **International comparison:** We did a preliminary review of over 50 existing hydrogen regulations[3] in the US, UK, and Australia, to identify areas where India lacks regulations. These include environment, emissions, waste disposal, gas network safety, gas transportation etc.

- **Technical and safety standards:** We identified areas where India lacks specific technical and safety standards for hydrogen. These include, liquid hydrogen storage, hydrogen metal hydride systems, piping of gaseous and liquid hydrogen, design, installation, commissioning, operation, maintenance, safety performance etc of gaseous hydrogen fueling stations. Recommendations include adopting existing international standards, with suitable modifications.

- **PNGRB Act and regulations:** A thorough review of the PNGRB Act 2006 revealed 20 regulation areas requiring modifications to incorporate hydrogen. These include modifying definitions within the Act to include hydrogen. A detailed review is provided in subsequent sections.

- **Global perspective:** Key initiatives and plans across the globe were assessed to evaluate India's position in the global race towards a hydrogen economy. This involved analyzing existing and planned regulatory frameworks, certification systems, blending projects, and national hydrogen roadmaps.

The key insights from the regulatory study are as follows -

Current Landscape:

- India currently lacks a comprehensive regulatory framework for hydrogen. There is also a lack of a regulatory agency which can cater to Hydrogen specifically. The **Ministry of New and Renewable Energy** (MNRE) has released a **National Green Hydrogen Mission**, which outlines the government's plan to develop a hydrogen economy in India.
- MNRE has released scheme guidelines to fund testing facilities and infrastructure and offers institutional support for development of standards and regulatory framework with a budget outlay of INR 200 Cr to upgrade existing testing facilities by identifying and addressing the gaps in components, technologies and processes being used, as well as to create new testing facilities/infrastructure.

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Global comparison and gaps in the Indian Regulatory structure:

[3] List of regulations has been provided in annexure

- The study examined global regulatory frameworks to benchmark India's progress. The analysis noted that the Indian clean Hydrogen Production Standard is defined for hydrogen produced from electrolysis and biomass. India does not currently have environment related regulations for hydrogen. In India, PNGRB regulates transportation via pipelines, as well as the safety plan for gas networks. However, its purview does not yet include hydrogen.
- Developing safety regulations, establishing certification schemes for green hydrogen, and creating a supportive policy framework for infrastructure development have been identified as crucial steps for developing an effective hydrogen framework.

Table 38: Gaps in the Regulatory Structure: India VS USA, UK and Aus

	REGULATIONS	INDIA	USA	UK	AUS	IDENTIFIED GAPS
1. Production	Explosive / Hazardous Good Management	✅	❌	✅	✅	★Clean Hydrogen Production Standard defined for hydrogen from electrolysis and biomass
	Environment Related Regulations and/or Regulations on Emissions	✅	✅	✅	✅	
	Clean Hydrogen Production Standard	★	✅	❌	❌	
	Explosive/ Hazardous substance management in Workplace/Accident Prev	✅	❌	✅	✅	
	Waste Disposal	✅	❌	❌	✅	
	Regulations for manufacturers of industrial chemicals	✅	❌	❌	✅	
2. Storage	Regulations for designing storage vessel	✅	❌	❌	❌	× Environment and related regulations
	Regulations for granting storage permissions/licenses for hydrogen	✅	✅	✅	❌	
	Safety regulations for storage at work	✅	✅	✅	❌	
	Control of operations of storage facility	✅	❌	✅	❌	
	Environment and related regulations	❌	❌	✅	❌	
3. Transportation	Rules for control/Risk Assessment over transportation of explosives	✅	✅	✅	❌	★Transportation via Pipelines is regulated by PNGRB. Current scope of PNGRB does not include Hydrogen but amendments are underway to include H_2 under the Act. ★ In India, PNGRB regulates Safety plan for Gas Networks. However, inclusion of hydrogen under its purview is not done yet. × Transportation via Waterways Hydrogen blending guidelines. GSR to be amended for hydrogen dispensing
	Transportation via Gas Cylinders	✅	❌	❌	❌	
	Transportation via Pipelines	❌	✅	✅	✅	
	Transportation via Road	✅	✅	✅	✅	
	Transportation via Rail	✅	✅	✅	✅	
	Transportation via Inland Waterways	❌	✅	✅	✅	
	Safety plan for Gas Networks	★	❌	✅	✅	
	Import Regulations	✅	✅	❌	❌	
	Hydrogen blending guidelines	❌	❌	✅	❌	
4. End Usage	Electricity Generation	❌	✅	❌	✅	Regulations on chemical and industrial use not clearly present Regulations for Electricity Production
	Export-Import	✅	✅	❌	✅	
	Chemical and Industrial Use	★	✅	✅	✅	
	Transport Use	✅	✅	✅	✅	

Contrasting the Indian regulations with international regulations reveals discrepancies between India's evolving framework and established global frameworks. This table examines these gaps, highlighting areas where Indian regulations diverge from international norms, potentially hindering the seamless integration of our nascent hydrogen economy into the global market. This analysis provides a critical roadmap for harmonizing Indian regulations with international best practices, paving the way for a robust and internationally compatible hydrogen ecosystem.

Ongoing Developments:

- PESO has completed a review of the 55 codes and 22 standards recommended for inclusion in the amendment of pressure vessel and gas cylinder rules. Insights of this study have been summarized in sub-section 6.4

- Collaboration is underway with BIS to adapt ISO 19880 for Gaseous Hydrogen Fueling Stations, considering Indian environmental conditions. This will involve expert and stakeholder reviews of safety distances.

- PESO is proposing the inclusion of Green Hydrogen regulations within the SMPV(U) Rules, 2016 and Gas Cylinder Rules, 2016.

- Standards and prototype testing procedures for Type-III and Type-IV Hydrogen gas cylinders are being reviewed for incorporation into the gas cylinder rules.

- PESO is adopting principles from NFPA-2 and NFPA-55 for safe site layout, hazard zone classification, and safety distances for both Gaseous and Cryogenic Liquid Hydrogen dispensing stations.

- SOPs and approval conditions for Green Hydrogen storage, transportation, and dispensation are under development

Recommended Landscape:

- PNGRB may be designated as the regulatory authority for hydrogen energy in India. The regulations in place for natural gas and city gas development can be expanded to include hydrogen. This has been delved into in upcoming sections.
- PNGRB Act may be amended.
- Pilot projects to test technical limits and amendments to PNGRB regulations

6.1 Mapping the regulatory structure for hydrogen markets in international geographies, namely USA, UK, Australia

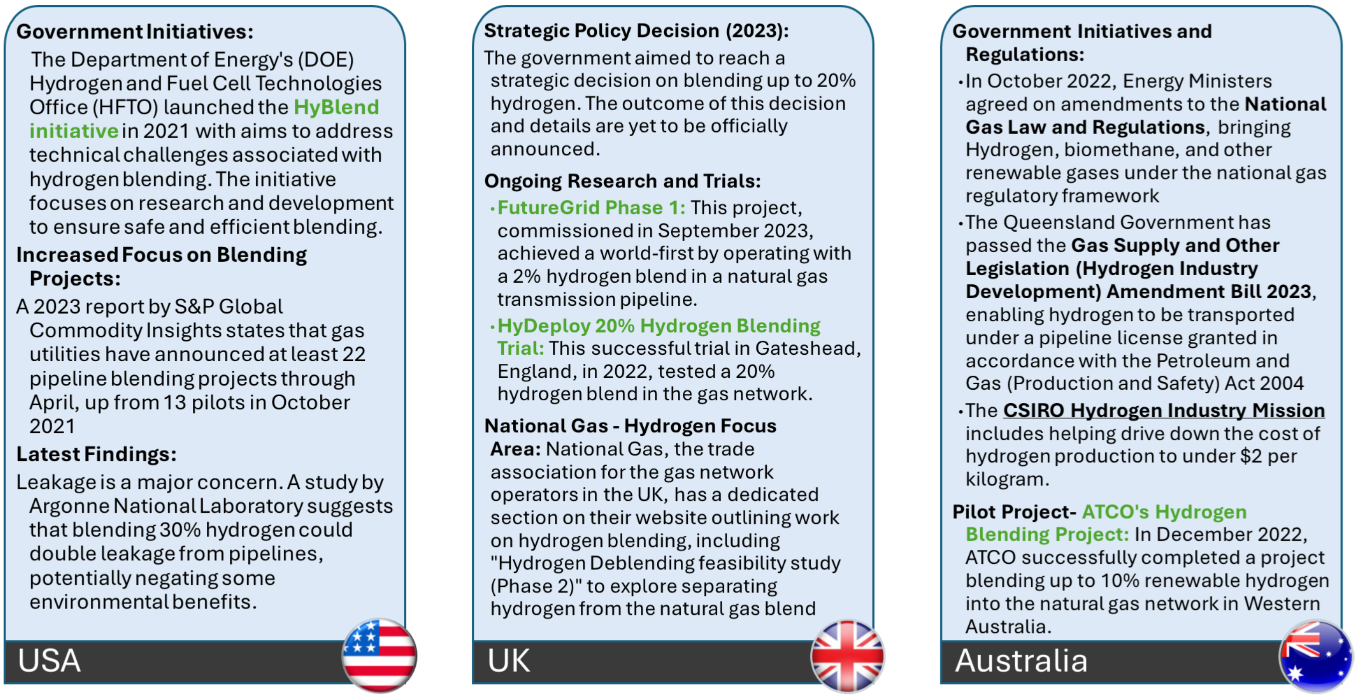
A review of the hydrogen value chain from production to end-use is crucial in order to identify the key government agencies that have jurisdiction in different areas, and the existing regulations, acts and laws. The goal is to provide a comprehensive overview of the regulatory landscape for hydrogen globally, and use it to benchmark the existing legislation in India and identify gaps.

This section examines the regulatory structures for hydrogen in four key regions: the United States, the United Kingdom, Australia, and the European Union. It assesses the different bodies and agencies responsible for hydrogen regulation in each country, as well as the specific regulations in place for each stage of the hydrogen value chain, from production to end use.

A detailed analysis of the regulatory structures of each country is included in the appendix of this report.

Furthermore, a study on recent trends and developments in hydrogen blending, conducted in three countries reveals the following key insights:

Figure 28: Recent Developments in Hydrogen Blending in USA, UK and Australia



6.2 Regulatory Framework in India

A similar analysis across the value chain was conducted for India. The Indian regulatory landscape for hydrogen is still in its early stages of development. The Ministry of New and Renewable Energy (MNRE) has initiated a National Green Hydrogen Mission, which outlines the government's plan to develop a hydrogen economy in India. However, the Green Hydrogen Mission is also in its early stages of development.

Table 39: Indian Regulatory Framework Summary Table

Value Chain	Classification	Agency	Regulation
Production	Green Hydrogen Production	Ministry of New and Renewable Energy (*Green Hydrogen Definition*)	*After discussions with multiple stakeholders, the Ministry of New & Renewable Energy has decided to define Green Hydrogen as having a well-to-gate emission (i.e., including water treatment, electrolysis, gas purification, drying and compression of hydrogen) of not more than 2 kg CO_2 equivalent / kg H2*
	Safety	Ministry of Environment, Forest and Climate Change (MoEFCC) (Department of Environment, Forests and Wildlife)	The Manufacture, Storage And Import Of Hazardous Chemical Rules, 1989
	Waste Disposal	Central Pollution Control Board	The Hazardous & Other Wastes (Management & Transboundary Movement) Rules, 2016
	Environment and	Central Pollution Control Board	The Air (Prevention and Control of Pollution)

	Emissions		Act, 1981
Storage		Petroleum and Explosives Safety Organization (PESO)	Static and Mobile Pressure Vessels (Unfired) Rules, 2016
		Ministry of Environment, Forest and Climate Change (MoEFCC) (Department of Environment, Forests and Wildlife)	The Manufacture, Storage and Import Of Hazardous Chemical Rules, 1989
Transportation	General	Petroleum and Explosives Safety Organization (PESO)	Static and Mobile Pressure Vessels (Unfired) Rules, 2016
	Transportation by Gas Cylinder	Petroleum and Explosives Safety Organization (PESO)	Gas Cylinder Rules 2016
End Usage	Imports	Ministry of Environment, Forest and Climate Change (MoEFCC) (Department of Environment, Forests and Wildlife)	The Manufacture, Storage and Import of Hazardous Chemical Rules, 1989
	FCEVs	Ministry of Road Transport and Highways of India (MoRTH) Automative Industry Standard and other Technical standards	

As per the regulatory framework in India, there is very little legislation that specifically relates to hydrogen.

Ministry of Environment, Forests and Climate Change (MoEFCC)- The Manufacture, Storage, and Import of Hazardous Chemical (MSIHC) Rules, 1989: Environment (Protection) Act, 1986 (Rules, n.d.)

The Manufacture, Storage, and Import of Hazardous Chemical (MSIHC) Rules, 1989 provide a set of regulations in India designed to ensure the safe handling and management of hazardous chemicals, including hydrogen. These rules were enacted under the Environment (Protection) Act, 1986, and are overseen by the Ministry of Environment, Forests and Climate Change (MoEFCC). Any person manufacturing or importing a hazardous chemical, including hydrogen, needs to obtain a license from the concerned authority. The license application requires detailed information about the chemical, its manufacturing/importing process, storage facilities, and safety measures in place. The rules specify stringent requirements for the storage and handling of hazardous chemicals. These include, but are not limited to:

- Maintaining separate, well-ventilated, and secure storage facilities.
- Implementing proper labelling and marking of containers.
- Employing appropriate safety equipment and personal protective gear.
- Regularly conducting safety inspections and maintaining records.

Petroleum and Explosives Safety Organization (PESO)

The Petroleum and Explosives Safety Organization (PESO), formerly known as Department of Explosives, since its inception on 05/09/1898, has been serving the nation as a nodal agency for regulating safety of hazardous substances such as explosives, compressed gas, and petroleum.

The PESO **Static and Mobile Pressure Vessels (Unfired) Rules, 2016** (PESO, n.d.), are a set of regulations in India governing the design, construction, manufacture, testing, import, installation, operation, maintenance, and inspection of unfired pressure vessels. These rules aim to ensure the safety of such vessels and prevent accidents due to leaks, explosions, or other failures. They apply to all types of unfired pressure vessels, including boilers, piping systems, storage tanks, reactors, and cylinders. The rules cover a wide range of pressures and capacities, ensuring safety for diverse industrial applications.
Key points covered in the SMPV(U) Rules are:

- Manufacturers, importers, and installers of pressure vessels must obtain licenses from the Petroleum and Explosives Safety Organization (PESO).
- Pressure vessels must comply with design, material, and construction standards specified in the rules.

- Mandatory inspections and tests are required before commissioning and throughout the operational life of a pressure vessel.
- Detailed procedures are outlined for operation, maintenance, and repair of pressure vessels.
- The SMPV(U) Rules 2016 play a critical role in ensuring the safety of personnel and property involved in the use of unfired pressure vessels.
- They promote safe manufacturing, installation, and operation practices, minimizing the risk of accidents and explosions.
- The rules contribute to a robust regulatory framework for the pressure vessel industry in India.

The PESO **Gas Cylinder Rules, 2016** (PESO, n.d.) are a set of regulations in India governing the storage and transportation of compressed gases in cylinders. These rules aim to ensure the safety of such cylinders and prevent accidents due to leaks, explosions, or other failures. The PESO GCR 2016 play a crucial role in ensuring the safety of gas cylinders in India. By implementing these rules, the government aims to prevent accidents and injuries caused by gas cylinder failures, protect workers and the public from hazards associated with these cylinders, promote safe practices in the design, manufacture, storage, transportation, and use of gas cylinders, and enhance India's industrial competitiveness by ensuring compliance with international safety standards.

The rules include detailed provisions covering various aspects of gas cylinders, including:

- Manufacture: The rules specify the materials, design standards, manufacturing processes, and safety features required for various types of gas cylinders.
- Storage: The rules specify the requirements for storing gas cylinders, including the type of storage facility, the location of the facility, and the safety measures to be in place.
- Transportation: The rules specify the requirements for transporting gas cylinders, including the type of vehicle, the loading and unloading procedures, and the safety measures to be in place.
- Use: The rules prescribe guidelines for the safe use of gas cylinders, including operator training, safety procedures, and maintenance schedules.

Recently, PESO released a draft amendment to the Gas Cylinder Rules 2016 which includes Hydrogen gas under the regulations. A summarized view of the same is presented here.

The Draft Gas Cylinders (Amendment) Rules, 2024 aim to update regulations regarding the manufacturing, filling, transportation, and possession of gas cylinders in India. Here are the key points:

- **Introduction of Compressed Hydrogen Gas (CHG):** The amendments propose including CHG cylinders under the regulations. They also specify a diameter range for CHG storage and filling cylinders.
- **Green Hydrogen Recognition:** The draft rules acknowledge "Green Hydrogen" produced from renewable energy sources.
- **Unique Identification for Cylinders:** The proposal mandates permanent and tamper-proof identification for cylinders and cryogenic containers. This could be in the form of a barcode, RFID tag, QR code, or any other electronic identification system. Existing cylinders will be given a one-year grace period to comply.
- **Enhanced Safety Measures for Flammable Gas Filling:** The amendments propose stricter electrical safety standards for facilities filling and storing flammable gas cylinders. These standards will likely align with IEC or IS/IEC 60079 series.
- **Tracking Cascade Systems:** The draft rules propose introducing tamper-proof identification plates for cascade frames (multiple cylinders connected). Additionally, record-keeping of details like name, date, serial number, and installation sequence of these cascades would be mandatory for manufacturers.
- **Hydrostatic Testing:** The amendments propose mandatory hydrostatic testing or hydrostatic stretch testing of cylinders every 3 years.

Overall, the Draft Gas Cylinders (Amendment) Rules, 2024 aim to improve safety standards, promote the use of green hydrogen, and enhance traceability within the gas cylinder industry.

Ministry of Petroleum and Natural Gas (MOPNG)

Recently, the petroleum ministry has suggested amendments in the Oilfield (Regulation and Development) Act, 1984 (the Act) via Oilfields (Regulation and Development) Amendment Bill, 2021 (draft amendment bill) by including hydrogen in the definition of 'mineral oils' to enable the government to grant a license for its exploration and production while promoting 'ease of doing business' in the country. This has prompted a push for a streamlined regulation of hydrogen in India through a well-defined legal framework (MOPNG, n.d.).

Ministry of Road Transport and Highways (MoRTH)

In September 2016, Ministry of Road Transport and Highways (MoRTH) has notified Hydrogen as a fuel for automotive application for Bharat Stage VI vehicles. In September 2020, MoRTH has specified the safety and type approval requirements for hydrogen fuel cell vehicles in Automotive Industry Standard (AIS) 157. Also, in September 2020, 18% blend of Hydrogen with CNG (HCNG) has been notified as an automotive fuel. (MoRTH, n.d.)

The Hazardous and Other Wastes (Management and Transboundary Movement) Rules, 2016 (CPCB, n.d.)

Hazardous Waste Management Rules are notified to ensure safe handling, generation, processing, treatment, package, storage, transportation, use reprocessing, collection, conversion, and offering for sale, destruction and disposal of Hazardous Waste. The occupier of any factory or premises, as defined under Rule 3(1)(21) of the HOWM Rules, 2016, is responsible for the safe and environmentally sound management of hazardous and other wastes. This includes obtaining authorization from the relevant State Pollution Control Board/Committee (SPCB/PCC) for various activities related to waste handling and management. The occupier must adhere to the conditions stipulated in the authorization and comply with provisions outlined in the HOWM Rules, 2016. Additionally, record-keeping, submission of annual returns, and compliance with import/export regulations for waste recycling/recovery/reuse/utilization are also mandatory requirements for the occupier.

The Air (Prevention and Control of Pollution) Act, 1981 (CPCB, n.d.)

Established to prevent, control, and abate air pollution, the Act empowers the Central Pollution Control Board (CPCB) to set National Ambient Air Quality Standards (NAAQS) and State Pollution Control Boards (SPCBs) to implement and enforce them. This Act lays down regulations to check emissions by manufacturing facilities.

Ministry of New and Renewable Energy:
2nd Meeting for National Green Hydrogen Mission (12th October 2023)

1. For Green Hydrogen produced through electrolysis or conversion of biomass:
   a. GHG emissions not greater than 2 kg CO2 eq./kg hydrogen
   b. taken as an average over the last 12 months.
2. Detailed methodology for measurement, reporting, monitoring, on site verification, and certification of green hydrogen derivatives shall be specified by MNRE.

The Bureau of energy efficiency shall be the nodal authority for accreditation of agencies for monitoring verification and certification of green hydrogen.

The Petroleum And Minerals Pipelines (Acquisition Of Right Of User In Land) Act, 1962

The Act provides for the acquisition of right of user in land [for laying pipelines for the transport of petroleum and minerals. **Suggested modifications to the Act :-**

- Inclusion of Hydrogen in the scope of the Act. "An Act to provide for the acquisition of right of user in land [for laying pipelines for the transport of petroleum, minerals and Hydrogen]"
- Addition of the definition of 'hydrogen' in section 2 of the Act
- **Short title, extent and application**: The title of the act will need to be modified to include hydrogen blended pipelines.
- **Definitions**: The definition of terms like 'petroleum' and 'minerals' will need to be expanded to include hydrogen.
- **Publication of notification for acquisition**: The notification for acquisition will need to include hydrogen blended pipelines.
- **Central Government or State Government or corporation to lay pipelines**: The act will need to specify that the Central Government, State Government, or corporation can lay hydrogen blended pipelines.
- **Power to enter land for inspection, etc.**: The act will need to specify that the power to enter land for inspection, etc. will also apply to hydrogen blended pipelines.
- **Compensation**: The compensation for damage, loss, or injury will need to include hydrogen blended pipelines.
- **Penalty**: The penalty for obstructing the laying of pipelines or damaging pipelines will need to include hydrogen blended pipelines.
- **Power to make rules**: The rules will need to be modified to include hydrogen blended pipelines.

6.3 Comparative analysis of Indian regulatory frameworks to international frameworks

Current hydrogen regulations in India are in a nascent stage. Petroleum and Explosives Safety Organization (PESO) acts as a nodal agency for regulating safety of hazardous substances such as explosives, compressed gases, and petroleum in India, and provides some regulations regarding the safe handling of hydrogen. Explosives Act 1884, Static and Mobile Pressure Vessels (Unfired) Rules, 2016, and Gas Cylinder Rules 2016 form the key legislations that regulate hydrogen in India. The following table provides a comparison of the Indian regulations to international regulations and identifies key gaps that need to be bridged by Indian regulatory agencies to establish a proper hydrogen regulatory framework in India.

Table 40: Comparative Summary of International Regulations

S.NO	VALUE CHAIN	INDIAN REGULATIONS	REGULATIONS IN USA	REGULATIONS IN UK	REGULATIONS IN AUSTRALIA
1.	**Production**	MNRE Green Hydrogen Definition- After discussions with multiple stakeholders, the Ministry of New & Renewable Energy has decided to define Green Hydrogen as having a well-to-gate emission (i.e., including water treatment, electrolysis, gas purification, drying and compression of hydrogen) of not more than 2 kg CO2 equivalent / kg H_2 MoEFCC - The Manufacture, Storage and Import of Hazardous Chemical Rules, 1989 (on approvals for industrial activity, of on-site and off-site	EPA (Regulations regarding environment & greenhouse gas emission) DOE (to develop clean hydrogen production standards)	Planning (Hazardous Substances) Regulations 2015 (safe handling of hazardous substances) Dangerous Substances and Explosive Atmospheres Regulations 2002 (Explosive management in workplace) Office of Gas and Electricity Markets	Dangerous Goods Safety (SH) Regulations 2007 (safe handling of hazardous substances) Work Health & Safety Act 2011 (Explosive in workplace) Recycling and Waste Reduction Act 2020 (on waste disposal) National Greenhouse & Energy Reporting Act 2007 (on greenhouse emissions) Australian Energy Market Act 2004 (on electricity and gas markets) Industrial Chemicals Act 2019 (regulations for

		emergency plans for prevention of major accidents, rules for storage of hazardous substances) CPCB- The Air (Prevention and Control of Pollution) Act, 1981 (General regulations regarding emissions, pollution, air quality control etc) CPCB-The Hazardous and Other Wastes (Management and Transboundary Movement) Rules, 2016 (on waste disposal)		(Ofgem) (strict health and safety requirements) Environment Agency (Environment related rules)	businesses manufacturing industrial chemicals)
2.	**Storage**	PESO- Static and Mobile Pressure Vessels (Unfired) Rules, 2016 (on vessels, fittings, valves etc. & certifications) MoEFCC - The Manufacture, Storage and Import of Hazardous Chemical Rules, 1989 (labeling and markings required on containers of hazardous substances)	Federal Energy Regulatory Commission (issue of certificates & Authorization to inject hydrogen for the purposes of subsurface storage) Occupational Safety and Health Administration (safe storage at work)	Planning (Hazardous Substances) Regulations 2015 (safe storage, licenses required over certain qty) DSEAR 2002 (Explosive storage in workplace) COMAH (control operation of storage facilities) EA (Environment Agency) (permit for storage)	Gas Supply (Safety & Network Management) Regulation 2022 (Safety and design plan for gas networks)- Definition of "gas" For the Act, Dictionary, definition of gas, each of the following is declared to be a gas— (a) hydrogen gas that is not mixed with another gas, (b) a mixture of hydrogen gas and either natural gas or liquefied petroleum gas.
3.	**Transportation**	PESO- Static and Mobile Pressure Vessels (Unfired) Rules, 2016 (rules for vessels for transport) PESO- Gas Cylinder Rules (on transportation via cylinders) MoEFCC - The Manufacture, Storage and Import of Hazardous Chemical Rules, 1989 (on import rules) PNGRB Regulations (Regulates gas network, recommendations on expanding the scope to include hydrogen have been discussed in subsequent sections)	BSEE (transport regulation for outer continental shelf) FERC (regulates import-export transport facilities) Pipeline and Hazardous Materials Safety Administration (Prescribes minimum safety requirements & transport of hazardous materials) US Coast Guard (Regulations for facilities transferring hazardous materials back and forth from a vessel to a facility) Regulations on RAIL, ROAD, WATERWAYS	Pipelines Safety Regulations 1996 (design regulations) The Gas Safety (Management) Regulations 18 (GSMR) 1996 (regulates percentage of hydrogen blending) DSEAR (requires businesses to carry out risk assessment associated with transportation of dangerous substances, including hydrogen) Regulations on RAIL, ROAD, WATERWAYS	Petroleum and Gas (Production and Safety) Act 2004 (Pipeline design and safety) National Transport Commission: Australian Code for the Transport of Dangerous Goods by Road & Rail (provides regulations for road and rail transport) Australian Maritime Safety Authority: Protection of the Sea (Prevention of Pollution from Ships) Act 1983 (regulates transport by waterways)
4.	**End Usage**	MoEFCC - The Manufacture, Storage and Import of Hazardous Chemical Rules, 1989 (on imports) PESO- Gas Cylinder Rules (on transportation) MoRTH- Automotive Industry Standard (for Hydrogen FCEVs) Other Technical standards(for	Different regulations for: • Auxiliary Power, Alternative Power Supply • Chemical and Industrial Use • Electricity	FCEVs Hydrogen use as fuel	Different regulations for: • Electricity Production • Export-Import

		Fuel cell vehicles, refueling stations etc)	Production • Import/Export Terminals • Transport use		

6.4 Comparison of Indian Technical Standards for Hydrogen with Global Standards

This section compares Indian Standards (IS) for hydrogen with internationally recognized standards from organizations like ISO and ASME. We dissect key areas of convergence and divergence, examining how India's framework navigates established international norms and identify potential areas for harmonization. This comparison will shed light on the strengths and weaknesses with potential for improvement within the Indian standards.

Table 41: Indian Technical Standards for Hydrogen in Global Context

	Components	International Standards	Indian Standards
PRODUCTION	Electrolysis	ISO 22734-2019	IS 16509:2020 standard for electrolytic hydrogen production
	Safety of Hydrogen systems	NFPA 2	IS 16749 : 2018 Basic considerations for the safety of hydrogen systems
STORAGE	Safety requirement for hydrogen storage/compression/and delivery system	NFPA-2 (Hydrogen Technologies Code)	-
	Facilities for production from fire hazards	NFPA 55 29 CFR 1910.103	-
	Liquid Hydrogen storage	EIGA 06/19 Safety in Storage, handling and distribution of Liquid hydrogen CGA P-12, NFPA 55	-
	Portable liquified H2 containers/ tanks	IS/ISO 13985:2006(EN) is under draft	SMPV rules
	Portable compressed H2 containers/tanks	ISO 7866 & ISO 9809-1,2,3 & ISO 11119-1,2 & 3	SMPV rules/ GSR
	Stationary liquified hydrogen gas containers and tanks	ISO 15869- Gaseous hydrogen and hydrogen blends	-
TRANSPORTATION	H2 in pipeline	ASME B31.12 Hydrogen piping and pipelines	Relevant parts of ASME 31.12 to be adopted for hydrogen blending of more than 20

	Portable liquified hydrogen containers & tanks	ISO 13985:2006	SMPV rules
	Portable compressed hydrogen cylinders, containers & tanks	ISO 7866 & ISO 9809123	SMPV rules, GSR
	Stationery liquified hydrogen gas container & tanks	ISO 15869 & ISO 21029-1/2018	
END USAGE	H2 in fuel systems	ISO 12619 Road vehicles- CGH2 and hydrogen/natural gas blends fuel system components	-
	Gaseous Hydrogen Fuelling Stations Design, installation, commissioning, operation, maintenance, safety performance etc	ISO 19880 Gaseous Hydrogen Fuelling Stations	-
	Fuel Cell Vehicles	ISO 14687-2 : 2012	IS 16061 (Part 2) : 2016 Hydrogen fuel - Product specification: Part 2 proton exchange membrane (PEM) fuel cell applications for road vehicles

In the stakeholder consultation dated 7 March 2024, PESO representatives shared valuable insights into hydrogen safety standards and regulations. This information will be instrumental in shaping the coming framework of Indian hydrogen markets.

- **Review of Codes and Standards:** PESO has completed a review of the 55 codes and 22 standards recommended for inclusion in the amendment of pressure vessel and gas cylinder rules.
- **ISO 19880 Harmonization:** Collaboration is underway with BIS to harmonize ISO 19880 for Gaseous Hydrogen Fueling Stations, considering Indian environmental conditions. This will involve expert and stakeholder review of safety distances.
- **Green Hydrogen Definition:** PESO is proposing the inclusion of Green Hydrogen definition within the SMPV(U) Rules 2016 and Gas cylinder Rules,2016.
- **Hydrogen Cylinder Standards:** Standards and prototype testing procedures for Type-III and Type-IV Hydrogen gas cylinders are being reviewed for incorporation into the gas cylinder rules.
- **Safety Standards for Hydrogen Dispensing:** PESO is adopting principles from NFPA-2 and NFPA-55 for safe siting, layout, hazard zone classification, and safety distances for both Gaseous and Cryogenic Liquid Hydrogen dispensing stations.
- **Green Hydrogen SOPs:** SOPs and approval conditions for Green Hydrogen storage, transportation, and dispensing are under development.

STANDARDS ASSESSED BY PESO FOR ADOPTION:

Category : Standards that can be adopted as it is

▶ Product Standards: Total 12 standards

Out of 12 standards 3 standards were already existing in the Gas cylinder Rules and the SMPV(U) Rules,2016. Remaining 9 standards will be adopted in consultation with BIS and stake holders for any amendments in the standards are required for suitability to Indian atmospheric conditions and density of population ,etc.

▶ Code of Project: Total 5 standards

These standards are related to the cryogenic liquid hydrogen at -253 degC, and process safety management in industries .Therefore deliberations with cryogenic & Process Industries , BIS,OISD and other stake holders for any atmospheric and process conditions. amendments in the standards are required for suitability to India

Category: Standards with amendments: Total 2

▶ 1. NFPA-2 Hydrogen Technologies code-

PESO reviewed this code, will adopt this code in consultation with BIS and stake holders for any amendments in the standards are required for suitability to Indian atmospheric conditions. The code is very exhaustive in nature contains 16 chapters, approx. 380 pages and PESO requested to all the stake holders and working group to specify the subject matter which has to be included in the rules.

▶ 2. Gas Cylinder Rules,2016

PESO has completed the work related to DRAFT amendment of Gas Cylinder Rules,2016 for inclusion of above mentioned codes and standards. PESO will incorporate/adopt all the codes and standards after duly notified by BIS and the inputs from working group as well as stake holders to avoid any duplicity in codes which may leads to compliance burden to the stake holders. Example: Hydrogen dispensing stations referred in NFPA-2 and ISO 19880 also. In this regard detail study is required to decide which safety distances to be considered for Hydrogen fuelling stations in line with Indian atmospheric conditions.

6.5 Identification of gaps in existing PNGRB regulations

The Petroleum and Natural Gas Regulatory Board (PNGRB) has played a crucial role in regulating and promoting the natural gas sector in India. It is responsible for issuing licenses for the development and operation of pipelines and infrastructure, ensuring these comply with safety and quality standards. PNGRB also regulates tariffs for the transportation of natural gas, aiming to ensure fairness and transparency in pricing. Additionally, it promotes competition through open access policies, which allow multiple operators to use existing pipeline networks. The board addresses consumer grievances and disputes, contributing to consumer protection. Furthermore, PNGRB supports the expansion and development of the natural gas network, overseeing the growth of infrastructure to enhance distribution and accessibility.

As the Petroleum and Natural Gas Regulatory Board (PNGRB) spearheads regulations for India's natural gas sector, a groundbreaking opportunity is emerging: exploring the inclusion of hydrogen blended natural gas under its purview. This has the potential to revolutionize India's energy landscape by facilitating a cleaner and more sustainable future. To facilitate this shift, a robust regulatory framework is crucial. This study identifies existing gaps in the current natural gas regulations that need to be addressed to effectively incorporate hydrogen blending and pave the way for India's green energy goals.

Recommended changes in The Petroleum and Natural Gas Regulatory Board Act, 2006

PNGRB Act 2006 and PNGRB regulations were studied to recommend areas where changes needed to be made in order to incorporate hydrogen under the application of such regulations.

A detailed review of the act and regulations, along with recommendations -

Table 42: Changes in PNGRB Act 2006

S.No	Section of the Act	Recommendation
1	Section 11 - Functions of the Board	It is recommended that blending of hydrogen in natural gas is expressly included in the above section as part of the functions of the board
2	Section 2 - Definitions	It is recommended that natural gas blends (with hydrogen) be notified under this section
		Given the fact that all regulations stemming from the Act, utilize the term "Natural Gas", it is proposed that the definition of Natural Gas be expanded to include "Blended Natural Gas" within the umbrella term of "Natural Gas". It is also suggested to have a separate definition for blended natural gas.
3	Section 14: Register	It is suggested that Section 14 of the PNGRB Act be amended to explicitly incorporate hydrogen-related activities within the scope of the Petroleum and Natural Gas Register. Specifically, subparagraph (a) should include entities engaged in marketing hydrogen and establishing and operating hydrogen related infrastructure including storage infrastructure.
5	Section 17: Application for Authorisation	Modify existing clauses (1) and (2): Include "or hydrogen" after "natural gas" to explicitly encompass hydrogen blending within the purview of authorization requirements for both common/contract carrier pipelines and city/local distribution networks.
6	Section 61: Power of the Board to make Regulations	Additions to be made in order to empower the board to make regulations and include hydrogen in its purview: •Technical specifications and safety protocols for hydrogen storage and blending infrastructure. •Blending ratios and quality standards for hydrogen-natural gas mixtures. •Monitoring and reporting requirements for hydrogen blending operations. •Certification and accreditation frameworks for relevant entities and equipment. •Economic and financial incentives for promoting hydrogen blending projects. •Any other matter necessary for the effective implementation of hydrogen blending in India.

The Petroleum and Natural Gas Regulatory Board Act, 2006 (hereinafter referred to as the "**Act**") is the foundational act that defines and establishes the Petroleum and Natural Gas Regulatory Board (hereinafter referred to as the "**Board**"), which is the regulatory body established for governing and regulating downstream activities in the petroleum and natural gas sector of India.

The Constitution of India, under schedule VII, serial number 53, demarcates regulation and development of petroleum and petroleum products, and other liquids and substances to be under the legislative ambit of the Union in derivation of which the Act was enacted by the Parliament of India with the following preamble: -

> *"An Act to provide for the establishment of Petroleum and Natural Gas Regulatory Board to* ***regulate the refining, processing, storage, transportation, distribution, marketing and sale of <u>petroleum, petroleum products and natural gas</u>****excluding production of crude oil and natural gas so as to protect the interests of consumers and entities engaged in specified activities relating to petroleum, petroleum products and natural gas and to ensure uninterrupted and adequate supply of petroleum, petroleum products and natural gas in all parts of the country and to promote competitive markets and for matters connected therewith or incidental thereto"* [emphasis supplied]

As highlighted by the preamble, the regulatory ambit of the Board extends to all matters pertaining to transportation natural gas and from a plain reading of it, does not require any additional modification to enable the Board to regulate blended hydrogen technology in natural gas pipelines.

The Board derives its authority to make regulations, by-laws, set technical standards and regulate the downstream sector of India from the Act and therefore, to introduce blending of hydrogen as an energy carrier, initially through the common carrier transmission pipelines system of the country, the Act would require the following suggestive amendments to equip the Board with the necessary power to regulate the introduction of the technology in the sector.

Section 11 - Functions of the Board

The functions of the Board under section 11 of the Act are as follows:

"11. Functions of the Board: -
The Board shall -

a. *Protect the interest of consumers by fostering fair trade and competition amongst the entities;*
b. *Register entities to-*
   - *(i) market notified petroleum and petroleum products and, subject to the contractual obligations of the Central Government, natural gas;*
   - *(ii) establish and operate liquified natural gas terminals;*
   - *(iii) establish storage facilities for petroleum, petroleum products or natural gas exceeding such capacity as may be specified by regulations*
c. *authorize entities to -*
   - *(i) lay, build, operate or expand a common carrier or contract carrier*
   - *(ii) lay, build, operate or expand city or local natural gas distribution network:*
d. *declare pipelines as common carrier or contract carrier;*
e. *regulate by regulations-*
   - *(i) access to common carrier or contract carrier so as to ensure fair trade and competition amongst entities and for that purpose specify pipeline access code;*
   - *(ii) transportation rates for common carrier or contract carrier;*
   - *(iii) access to city or local natural gas distribution network so as to ensure fair trade and competition amongst entities as per pipeline access code;*
f. *in respect of notified petroleum, petroleum products and natural gas-*
   - *(i) ensure adequate availability;*
   - *(ii) ensure display of information about the maximum retail prices fixed by the entity for consumers at retail outlets;*
   - *(iii) monitor prices and take corrective measures to prevent restrictive trade practice by the entities;*
   - *(iv) secure equitable distribution for petroleum and petroleum products;*
   - *(v) provide, by regulations, and enforce, retail service obligations for retail outlets and marketing service obligations for entities;*
   - *(vi) monitor transportation rates and take corrective action to prevent restrictive trade practice by the entities;*
g. *levy fees and other charges as determined by regulations;*

h. maintain a data bank of information on activities relating to petroleum, petroleum products and natural gas;
i. lay down, by regulations, the technical standards and specifications including safety standards in activities relating to petroleum, petroleum products and natural gas, including the construction and operation of pipeline and infrastructure projects related to downstream petroleum and natural gas sector;
j. perform such other functions as may be entrusted to it by the Central Government to carry out the provisions of this Act." [emphasis supplied]

*Therefore, it can be concluded that to empower the PNGRB to regulate the storage and transportation of hydrogen gas, **the objects of the PNGRB Act, 2006 andSection 11 of the PNGRB Act, 2006 need to be amended**.*

It is recommended that blending of hydrogen in natural gas is expressly included in the above section as part of the function of the board

Section 2 - Definitions

I. Recommendation changes in Clause 2(zc) of the Act

The definition of "Notified petroleum, petroleum products and natural gas" under clause 2(zc), is reproduced below:

> *"Notified petroleum, petroleum products and natural gas' means such petroleum, petroleum products and natural gas as the Central Government may notify from time to time after being satisfied that it is necessary or expedient so to do for maintaining or increasing their supplies or for securing their equitable distribution or ensuring adequate availability";* [emphasis supplied]

Recommendation: It is recommended that natural gas blends (with hydrogen) be notified under the above section. This is not a change within the provisions of the Act; rather the recommendation to notify natural gas blends with Hydrogen.

II. Expanding the scope of the umbrella term "Natural Gas"

The Act, under **clause 2(za),** defines natural gas in the following manner:

> *"natural gas" means gas obtained from bore-holes and consisting primarily of hydrocarbons and includes-*
> *(i) gas in liquid state, namely, liquefied natural gas and degasified liquefied natural gas,*
> *(ii) compressed natural gas,*
> *(iii) gas imported through transnational pipelines, including CNG or liquefied natural gas,*
> *(iv) gas recovered from gas hydrates as natural gas,*
> *(iv) methane obtained from coal seams, namely, coal bed methane, but does not include helium occurring in association with such hydrocarbons;"* [emphasis supplied]

Recommendation: Given the fact that all regulations stemming from the Act, utilize the term "Natural Gas", it is proposed that the definition of Natural Gas be expanded to include "Blended Natural Gas" within the umbrella term of "Natural Gas".

It is also suggested to have a separate definition for *blended natural gas* as Natural Gas blended with (up to a certain amount of) hydrogen.

III. <u>Adoption of a separate definition of Blended Natural Gas</u>

The Act under clause 2(za) gives an inclusive definition of Natural Gas in reference to its application under the Act. In light of the government's intention to promote blending of natural gas with hydrogen, it is recommended that a separate definition of blended natural gas is introduced in the Act, to serve two purposes:

a. First being, that it would set a limit on the composition ratio of natural gas with hydrogen that is required to be maintained to be classified as "Blended Natural Gas"
b. Secondly, usage of blended natural gas in addition to wherever natural gas has been mentioned throughout the Act, would ensure that such blended natural gas is also subjected to the power of the board under the Act in the same manner as the traditional natural gas.

Section 14: Register

Section 14 of the Act, empowers the Board to maintain a register which shall contain details of the following authorities:

"....................
(a) Registered for-
(i) Marketing notified petroleum, petroleum products or natural gas, or
(ii) Establishing and operating liquefied natural gas terminals, or
(iii) Establishing storage facilities for petroleum, petroleum products or natural gas exceeding such capacity as may be specified by regulations.

(b) Authorized for –
(i) Laying, building, operating or expanding a common carrier, or
(ii) Laying, building, operating or expanding a city or local natural gas distribution network, as may be provided by the Board by regulations

........................" [emphasis supplied]

Recommendation: It is suggested that Section 14 of the PNGRB Act be amended to explicitly incorporate hydrogen-related activities within the scope of the Petroleum and Natural Gas Register.

Specifically, subparagraph (a) should include entities engaged in marketing hydrogen and establishing and operating hydrogen related infrastructure including storage infrastructure.

Section 17: Application for Authorisation

In furtherance to the power of the Board to authorize entities to lay, operate, and expand pipeline networks, the subsequent section provides for the manner and mode of forwarding an application by an entity to seek such authorization. Subsections (1) and (2) as reproduced below, are recommended to be amended in the manner given below:

i."*An entity which is laying, building, operating, or expanding or which proposes to lay, build or expand, a pipeline as a common carrier or contract carrier shall apply in writing to the Board for obtaining an authorization under this Act.*

Provided that an entity laying, building, operating, or expanding any pipeline as common carrier or contract carrier authorized by the Central Government at any time before the appointed day shall furnish the particulars of such activities to the Board within six months from the appointed day.

ii.*An entity which is laying, building, operating or expanding, or which proposes to lay, build, operate or expand, a city or local natural gas distribution network shall apply in writing for obtaining an authorization under this Act".*

Recommendation: Modify existing clauses (1) and (2): Include "or hydrogen" after "natural gas" to explicitly encompass hydrogen blending within the purview of authorization requirements for both common/contract carrier pipelines and city/local distribution networks.

Rationale:
- Creating a dedicated clause for hydrogen blending applications ensures clarity and simplifies the authorization process for this specific activity.
- Requiring a detailed plan ensures adherence to safety regulations and technical standards for hydrogen infrastructure, mitigating potential risks.
- Explicitly mentioning hydrogen in existing clauses reinforces the PNGRB's oversight of all affairs pertaining to natural gas and hydrogen blends within its jurisdiction.

Section 61: Power of the Board to make Regulations

The Board derives its authority to make regulations and rules pertaining to affairs of petroleum, petroleum products and natural gas through the provisions of Section 61. The section provides an extensive list of subject matters on which the Board has been given due authority to make regulations and rules; however, in view of introducing the practice of hydrogen blending within the present frameworks, provisions empowering the Board in regard to the following are recommended to be added within the purview of the aforementioned section to provide explicit and clear authority to the Board:

A. Technical specifications and safety protocols for hydrogen storage and blending infrastructure.
B. Blending ratios and quality standards for hydrogen-natural gas mixtures.
C. Monitoring and reporting requirements for hydrogen blending operations.
D. Certification and accreditation frameworks for relevant entities and equipment.
E. Economic and financial incentives for promoting hydrogen blending projects.
F. Any other matter necessary for the effective implementation of hydrogen blending in India.

Further, an analysis of PNGRB Regulations was conducted to identify which regulations need to be amended to include hydrogen blending. The following were the key findings:

Table 43: PNGRB Regulations Analysis

Regulations That Require Amendment	Regulations That Require Testing For Hydrogen Blending	Regulations That Do Not Require Any Change
Authorizing Entities to Lay, Build, Operate or Expand City or Local Natural Gas	Technical Standards and Specifications including Safety	Exclusivity for City or Local Natural Gas Distribution Network

Distribution Networks	Standards for City or Local Natural Gas Distribution Networks	
Determination of Transportation Rate for CGD and Transportation Rate for CNG	Integrity Management System for City or Local Natural Gas Distribution Networks	Code of Practice for Quality of Service for City or Local Natural Gas Distribution Networks
Access Code for City or Local Natural Gas Distribution Networks	Determining Capacity of City or Local Natural Gas Distribution Network	Guiding Principles for Declaring City or Local Natural Gas Distribution Networks as Common Carrier or Contract Carrier
Authorizing Entities to Lay, Build, Operate or Expand Natural Gas Pipelines	Access Code for Common Carrier or Contract Carrier Natural Gas Pipelines	Guiding Principles for Declaring or Authorizing Natural Gas Pipeline as Common Carrier or Contract Carrier
Affiliate Code of Conduct for Entities Engaged in Marketing of Natural Gas and Laying, Building, Operating, or Expanding Natural Gas Pipeline	Emergency Response & Disaster Management Plan (ERDMP) Regulations	Imbalance Management Services Regulations
Determination of Natural Gas Pipeline Tariff		
Technical Standards and Specifications including Safety Standards for Natural Gas Pipelines		
Determining Capacity of Petroleum, Petroleum Products and Natural Gas Pipeline		
Integrity Management System for Natural Gas Pipelines		
Petroleum And Natural Gas Register		

The detailed analysis of recommended changes in regulationshas been attached to the appendix of this report.

6.6Global initiatives and plans for establishing hydrogen economy

Across the globe, nations are increasingly recognizing the immense potential of hydrogen as a clean and versatile fuel, leading to a surge of initiatives and strategic plans aimed at developing a robust hydrogen economy. This section analyzes the diverse efforts undertaken by various countries to establish the foundation for a low-carbon future fueled by hydrogen..

Existing and Planned Hydrogen Regulatory Frameworks and Certification Systems (IEA, n.d.)

Governments worldwide are simultaneously taking steps to implement regulations and certification systems pertaining to the environmental attributes of hydrogen. There are currently seven national and supranational governments with regulatory frameworks in place. A further six countries have announced forthcoming regulations, although the specific methodologies to demonstrate compliance with these frameworks are yet to be determined.

While these certification systems and regulatory frameworks share certain similarities in terms of scope, system boundaries and eligibility criteria, there are also significant divergences. This variability poses challenges for project developers – particularly those aiming to participate in a potential global market – who need to undertake ad-hoc certification processes for each country they wish to access, resulting in increased transaction costs.

Table 44: Hydrogen Regulatory Frameworks and Certification Systems

Government	Name	Purpose	Product	Status	Criteria
Australia	Guarantee of Origin certificate scheme	Voluntary	Hydrogen, hydrogen carriers	Under development	No eligibility criteria. The only requirement is to implement an emissions accounting methodology for the hydrogen produced
Canada	Clean Hydrogen Investment Tax Credit	Regulatory, access to tax credits	Hydrogen, ammonia	Under development	Production below certain emissions intensity levels (<0.75, 0.75-2, 2-4 g CO2-eq/g H2). For ammonia, only one emissions intensity level is defined (<4 g CO2-eq/g H2-eq)
Denmark	Guarantee of Origin certificate scheme	Voluntary	Hydrogen, hydrogen – based fuels	Operational	Production from renewable electricity
European Union	Renewable Energy Directive II	Regulatory, count against renewable energy targets	Hydrogen, hydrogen – based fuels	Operational (certification under development)	Production from renewable electricity (or grid electricity with <65 g CO2-eq/kWh) meeting criteria on temporal and geographical correlation and additionality of renewable generation.
France	France Ordinance No. 2021-167	Regulatory, access to public support programs	Hydrogen	Under development	"Low-carbon hydrogen": production with emissions intensity <3.38 g CO2-eq/g H2. "Renewable hydrogen": production with emissions intensity <3.38 g CO2-eq/g H2 and renewable sources
Japan	Basic Hydrogen Strategy	Regulatory, access to public support	Hydrogen, hydrogen – based fuels	Under development	Production with emissions intensity <3.4 g CO2-eq/g H2
Korea	Clean Hydrogen Certification Mechanism	Regulatory, access to public support	Hydrogen	Under development	Production with emissions intensity <4 g CO2-eq/g H2.
India	Green Hydrogen Standard for India	Regulatory, access to public support	Hydrogen	Under development	Production from renewable energy with emissions intensity <2 g CO2-eq/g H2.
Italy	Guarantee of Origin certificate scheme	Voluntary	Electricity and renewable gases	Operational	Production from renewable sources

			(incl. hydrogen)		
Netherlands	Guarantee of Origin certificate scheme	Voluntary	Hydrogen	Operational	Production from renewable electricity
Spain	Guarantee of Origin certificate scheme	Voluntary	Renewable gases (incl. hydrogen)	Operational	Production from renewable electricity
United Kingdom	Low Carbon Hydrogen Standard	Regulatory, access to public support	Hydrogen	Operational (certification under development)	Production with emissions intensity <2.4 g CO2-eq/g H2.
United Kingdom	Renewable Transport Fuel Obligation	Regulatory, access to public support	Hydrogen (use in transport)	Under development	Production from renewable energy (excluding bioenergy) with emissions intensity <4.0 g CO2-eq/g H2.
United States	Clean Hydrogen Production Std; Tax Credit	Regulatory, access to public support	Hydrogen	Under development	Production below certain emissions intensity levels (<0.45, 0.45-1.5, 1.5-2.5, 2.5-4 g CO2-eq/g H2) eligible for different levels of investment tax credits support.

National hydrogen roadmaps and strategies since September 2022 (IEA, n.d.)

These announcements of hydrogen strategies serve as the biggest driver of government funding. India's National Green Hydrogen Mission includes nearly INR 2 billion (Indian rupees) (~USD 25 million) subsidy to produce 5 Mt of hydrogen for domestic consumption and 10 Mt of hydrogen for exports by 2030. The United States adopted the US National Clean Hydrogen Strategy and Roadmap, revising their strategy to accord with recent carbon capture, utilisation and storage (CCUS), renewables, and sustainable aviation fuel (SAF) production tax credits and funding opportunities. In addition, Belgium, Germany, Japan and Korea have updated their existing hydrogen strategies, and a number of countries, particularly in Europe, are in the process of revising their strategies.

The new and updated strategies show an increase in global ambitions to deploy hydrogen technologies, as reflected in government targets for low emission hydrogen production, which now account for 27 to 35 Mt, compared with 15 to 22 Mt at the time the GHR 2022 was released (Table 11). The biggest contributors to this increase are the targets of the United States (10 Mt of "clean" hydrogen), India (5 Mt of "green" hydrogen) and Namibia (1–2 Mt of "green" hydrogen).

Table 45: National hydrogen roadmaps and strategies since September 2022

Government	Description
Algeria	Target to produce and export 30-40 TWh of hydrogen and hydrogen-based fuels by 2040. Focus on pilot projects until 2030 to start up the sector.
Brazil	The 2023-2025 Triennial Work Plan of the National Hydrogen Program defines the strategy of the country, with three timeframes: by 2025, deploy low-carbon hydrogen pilot plants across the country; by 2030, consolidate Brazil as a competitive low-carbon hydrogen producer; and by 2035 consolidate low-carbon hydrogen hubs
Costa Rica	Target to install 0.15-0.50 GW of electrolysis capacity, to replace 8-10% of liquefied petroleum gas (LPG) with "green" hydrogen and to deploy 100-250 fuel cell electric vehicles (FCEVs) and 200-600 fuel cell heavy-duty trucks by 2030.
Ecuador	Target to install 3 GW of electrolysers by 2040 and establish regulations for domestic hydrogen use and potentially for export to international markets.
India	Target to produce 5 Mt of "green" hydrogen by 2030 (with associated 125 GW of renewable capacity additions) with additional potential to reach 10 Mt/yr with exports. Interest in developing a domestic electrolyser manufacturing industry.

Israel	Plans explore options to integrate hydrogen into the national energy mix, along with consideration of underground storage.
Kenya	Target to install 150-250 MW of electrolysers and to produce 300-400 kt of nitrogen fertilisers by 2032. Aim to develop a local "green" fertiliser industry to decrease dependency on imported fertilisers.
Namibia	Target to produce 1-2 Mt of "green" hydrogen by 2030 and 10-15 Mt by 2050. Aims to develop three hydrogen valleys* to start production and use.
Panama	In transport, the country aims to increase hydrogen and derivatives for maritime fuels bunkering to 5% by 2030. Target to produce 0.5 Mt of hydrogen by 2030.
Singapore	Aim to transform Singapore into a hub for hydrogen and hydrogen fuels in the Pacific. Strong focus on electricity generation, with an estimate that hydrogen could meet up to 50% of electricity demand in 2050, as well as aviation and maritime.
Sri Lanka	Roadmap includes plans to export hydrogen derivatives by 2030.
Türkiye	Target to install 2 GW of electrolysers by 2030, 5 GW by 2035 and 70 GW by 2053. Support for demonstration projects for "blue" hydrogen production.
United Arab Emirates	Strategy includes a forecast for the production of 1.4 Mt of hydrogen by 2030, 7.5 Mt by 2040 and 15 Mt by 2050, through a mix of electrolysis powered with renewable and nuclear electricity, and natural gas with carbon capture, utilisation and storage (CCUS).
United States	Target to produce 10 Mt of "clean" hydrogen by 2030, 20 Mt by 2040 and 50 Mt by 2050. Update every 3 years (required by the Bipartisan Infrastructure Law).
Uruguay	Target to install 1-2 GW of electrolysers by 2030 and 10 GW by 2040, with initial focus on domestic demand in the short term and exports in the long term.
Belgium (update)	Vision structured around four pillars: become an import/transit hub for renewable hydrogen in Europe, expand technology leadership, establish a robust domestic market and international co-operation.
Germany (update)	Target to install 10 GW of electrolysers by 2030, and increased demand in industry and transport to replace larger shares of natural gas, with over 1 800 km of pipeline infrastructure.
Japan (update)	Interim target for 12 Mt of hydrogen demand by 2040 (complementing previous targets for 3 Mt by 2030 and 20 Mt by 2050) and to meet 1% of the gas supply in existing networks with synthetic methane by 2030, increasing to 90% by 2050. Target to install 15 GW of electrolysis globally. Shift focus from FCEVs to the use of hydrogen in applications, notably in steel and petrochemical industries.
Korea (update)	Updated target to reach 2.1% of total electricity production with hydrogen and ammonia by 2030, and 7.1% by 2036. Creation of a framework for a Clean Hydrogen Certification Mechanism to be released by the end of 2023.

On the demand side, however, there has been no increase in ambition, and only two significant developments. In the European Union there has been a political agreement to set binding targets for the use of renewable fuels of non-biological origin (RFNBO) in industry, transport and aviation by 2030, though some targets were less ambitious than those proposed in the 'Fit for 55' package in 2021 (e.g. 42% of hydrogen demand to be met with renewable hydrogen, compared to an initial target of 50%). Binding targets of this kind can send a clear signal to industry about a future marketplace for low-emission hydrogen and hydrogen-based fuels. In Japan, the updated Basic Hydrogen Strategy includes a target to meet 1% of the gas supply in existing networks with synthetic methane by 2030.

7. Roadmap for India's Hydrogen Growth

India stands at a pivotal juncture in its energy journey. Decarbonization efforts are gaining momentum, and clean energy sources like hydrogen are poised to play a transformative role. Recognizing this potential, the Government of India launched the National Green Hydrogen Mission (NGHM) in January 2023, with the ambitious vision of establishing India as a global leader in green hydrogen production, utilization, and export.

This roadmap serves as a critical next step towards realizing the NGHM's vision. Developed through comprehensive analysis undertaken in Tasks 1-4, it outlines a strategic plan for developing a robust hydrogen infrastructure in India by 2040.

It addresses the need for a well-defined pathway to navigate the complexities of hydrogen infrastructure development, commercial challenges and regulatory provisions.

This roadmap aims to-

- Enable the gradual blending of hydrogen into existing natural gas pipelines
- Facilitate the development of dedicated hydrogen pipelines to deliver hydrogen to large-scale industrial users like refineries and chemical plants.

7.1 Roadmap for hydrogen blending

The conclusions of Technical, Commercial and Regulatory assessments have enabled the creation of a roadmap to realize the NGHM's vision.

Short Term Roadmap- 2024-2025

Action Items in the short-term:

Technical	• Conducting **technical assessment** of the existing pipeline and CGD networks and connected end users in Indian context. • Comprehensive technical study of materials for major pipelines and CGD networks. This would involve collecting specific information about the material used for each segment of the gas network
Testing	• Physical testing at a test site in India where actual gas flow conditions will be simulated by installing small pipeline and CGD network sections with all materials as are in the real gas network (as identified from the technical study above). • Different percentage blends of hydrogen with natural gas will be tested under varying temperature and pressure conditions to simulate multi-year operations.
Regulatory	• **Modification of PNGRB Act**(refer to section 8.5)to allow PNGRB to regulate blended natural gas with hydrogen/pure hydrogen pipeline and storage infrastructure. • **Collaboration with PESO for technical standards** and regulations round hydrogen storage and dispensing

We identified key activities that PNGRB should focus over next 12 months to support hydrogen blending in natural gas pipelines:

- Modification of PNGRB Act to allow PNGRB to regulate blended natural gas with hydrogen/pure hydrogen pipeline and storage infrastructure.

- Conduct detailed technical assessment for the major pipelines and CGD networks. The detailed technical assessment would include review of P&ID information for the equipment, pipeline network etc. to identify blending limits for each pipeline.
- PNGRB board may visit the UK and hold bilateral meetings with (1) National Grid Transco (2) OFGEM (3) DESNZ (4) SGN (gas distribution company); and site visits to (a) HyDeploy project (b) Spadeadam facility to witness the testing being done for hydrogen blending in transmission and distribution systems
- Work with PESO for technical standards and regulations round hydrogen storage and dispensing
- Physical testing at a test site with different blend percentages (5%, 10%, 20%) in India where actual gas flow conditions will be simulated by installing small pipeline and CGD network sections with all materials as are in the real gas network (as identified from the technical study above).
- Different percentage blends of hydrogen with natural gas will be tested under varying temperature and pressure conditions to simulate multi-year operations.
- Development of safety norms for accommodating different percentage of blending.
- Pilots of hydrogen blending in natural gas pipeline line network at different percentage

Expected outcomes in the short-term:

The expected outcomes of this phase are:

- A number of hydrogen blending projects piloted in various locations,
- A comprehensive and reliable database of the technical, economic, environmental, and social performance and impacts of hydrogen blending, which can inform and support the decision-making and planning for the subsequent phases.
- A set of standards and guidelines for hydrogen blending, which can ensure the safety, quality, and compatibility of hydrogen blending with the existing gas infrastructure and equipment.
- A range of business models and financing mechanisms for hydrogen blending projects, which can attract and mobilize the investment and participation of various stakeholders.
- A revised and updated policy and regulatory framework for hydrogen blending, which can facilitate and incentivize the development and deployment of hydrogen blending projects.

Medium Term Roadmap- 2025-2030

Action Items in the medium-term:

Technical	• Develop analytical tools and framework to identify regional areas where hydrogen blending may be started. • Start hydrogen blending at DRS stations with 5% blend and monitor any losses/leaks • Retrofit pipeline infrastructure including deblending solutions for CNG stations and monitor progress • Gradually progress towards higher percentage of hydrogen blending upto 10% and monitor performance for key components of NG infrastructure • Conduct material testing and ensure no safety or performance issues • Implement significant retro fitment for compressors, gas turbines etc. before moving to higher percentage of hydrogen blend • Used closed loop network to test for higher blending of 15% and 20% and its impact on industrial boilers and residential and commercial consumers • Gradually implement higher blending ratio, if closed loop network test shows no safety concerns • Gradually roll out higher blending in regional network

Regulatory	• **Modification of key regulations** to allow for hydrogen /hydrogen blending NG through pipeline. • Modification of **safety standard for hydrogen to be used after blending**
Business Models	• Develop business models or hydrogen blending and use stakeholder consultations. • Government funding schemes like SIGHT Programme and VGF Scheme
Skillset development	• Training **courses for managing blended infrastructure** • Partnership with **global institutes** for hydrogen blending training and certification courses • Trainings and **skill development** is needed across the entire value chain, with focus on**Pipeline design, Retrofitment, Pipeline O&M, Blending H_2**. • Persons technically qualified in hydrogen to be part of projects involving hydrogen blending. • Hydrogen Expertise: Under**standing the properties, handling procedures, and safety protocols** specific to hydrogen. • Blending & System Management: **Knowledge of blending processes, monitoring equipment performance with hydrogen blends, and optimizing gas flow** for the mixed gas. • Material Compatibility: Assessing the **impact of hydrogen on existing pipeline infrastructure** and identifying materials suitable for hydrogen blends. • Combustion & Appliance Performance: Understanding **how hydrogen blends affect combustion characteristics and adapting maintenance practices** for appliances using the blended gas.

Expected outcomes in the medium-term:

The expected outcomes of this phase are:
- Developing and validating models and methods for predicting the performance and emissions of hydrogen-blended gas combustion in different types of appliances and burners.
- Establishing standards and guidelines for safe and efficient operation of appliances using hydrogen blends, including optimal hydrogen content, flame stability, ignition, and control strategies.
- Identifying and addressing potential issues and risks associated with hydrogen-blended gas combustion.
- Demonstrating the feasibility and reliability of hydrogen-blended gas combustion in various applications, such as domestic heating, cooking, industrial processes, and power generation.

Long Term Roadmap- 2030-2040

Action Items in the long-term:

Technical	• **Roll out of hydrogen blending at safe limits pan India (upto 20% blending)**

Expected outcomes in the long-term:

The expected outcomes of this phase are:

- To develop a robust and resilient hydrogen pipeline network that can transport large volumes of hydrogen across regions and borders, and integrate with existing natural gas infrastructure.
- To enable the widespread adoption of hydrogen as an alternative fuel for various end-use sectors, such as power generation, industry, transport, and buildings, and support the decarbonization of these sectors.
- To create a competitive and innovative hydrogen market that supports the development of new products, services, and business models based on hydrogen, and fosters cross-sectoral and cross-regional collaboration.
- To enhance the public awareness and acceptance of hydrogen as a safe and clean energy carrier, and address the regulatory, policy, and social barriers to its deployment.

7.2 Roadmap for pure hydrogen distribution

While long distance transnational natural gas pipeline may be used to distribute blended hydrogen, applications such as refineries, non-urea fertiliser plants, chemical and iron and steel plants require pure hydrogen. Thus, we have identified the key states with large refineries, non-urea fertilizer plants and iron and steel plants as promising locations for hydrogen hubs to develop pure hydrogen pipelines. Pure hydrogen pipelines can be established in the states of *Maharashtra, Tamil Nadu, Andhra Pradesh, and West Bengal, Gujarat, Kerala*- Refineries, fertilizer plants and iron & steel plants across the country have been mapped, to figure out locations where demand for green hydrogen will be the maximum.

The development of hydrogen hubs provide support for hydrogen pipeline and storage infrastructure. The overall budgetary outlay of INR 200 Cr was envisaged by MNRE. The support for common user facilities include:

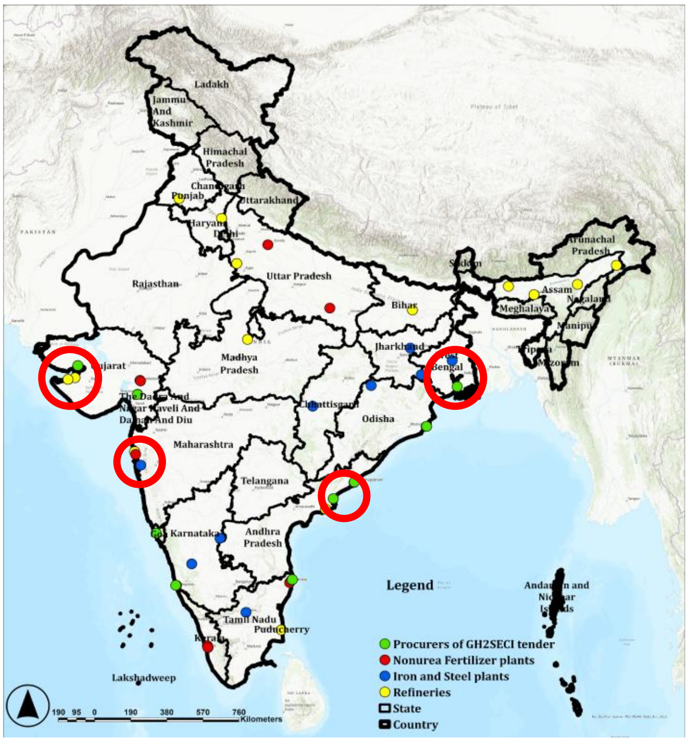
- Storage and transport facilities for GH2 and derivatives
- **Development or upgradation of pipeline infrastructure**
- GH2 powered vehicle refueling capacity
- Hydrogen compression and/or liquefaction facilities
- Hydrogen storage systems
- Water treatment facility
- Development of bunkering facility
- Infrastructure upgradation for shipping
- Land redevelopment
- Energy storage
- Any other infrastructure required

The scheme is relevant for PNGRB as:

- The development or upgradation of H2 pipelines would get support under this scheme.
- The new hydrogen only pipelines should be developed at regional level as common user facility.
- The pipeline would support multiple refineries, ammonia plants and industry requiring hydrogen as feedstock

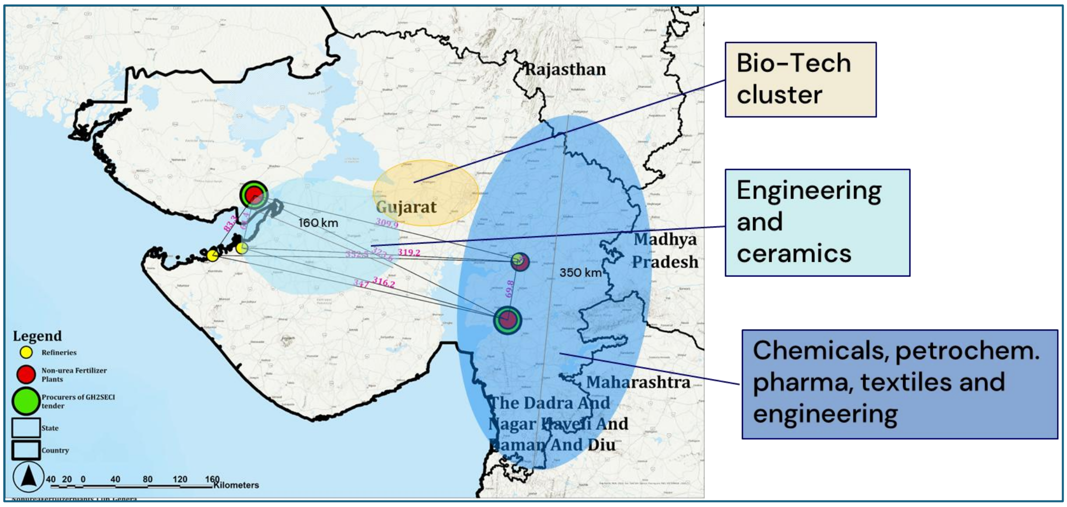
The chart below shows potential states suitable for developing pure hydrogen pipelines based on current SECI tenders under 2A SIGHT scheme and anchor customers for pure hydrogen.

Figure 29: Demand clusters for Hydrogen



Industrial zones near anchor consumers may provide additional demand, thereby requiring a hydrogen distribution network. A noteworthy demand cluster for Hydrogen would be Gujarat, since it is home to refineries, fertilizer plants and industrial zones. Gujarat's **Morbi** district is home to the world's second-largest ceramic production cluster housing more than 1,000 units.

Figure 30: Gujarat as a hydrogen demand hub



PNGRB, apart from developing a blended hydrogen roadmap, should also regulate pure hydrogen pipelines.

The key action areas for implementation of pure hydrogen pipelines include the following: -

- Modification of PNGRB Act to allow PNGRB to regulate pure hydrogen pipelines and storage infrastructure.

- PNGRB may provide hydrogen storage and distribution license, in line with CGD entities, for setting up common user facilities for storage and distribution of hydrogen in hubs.
- New regulations governing various aspects of pure hydrogen network, including authorization to develop hydrogen distribution network, capacity determination, tariff determination, technical standards and safety regulations.
- Demand assessment of hydrogen for industrial and chemical purposes near identified hubs.
- Development of business models to ensure capex recovery and promote usage of green hydrogen in local network.

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Acronyms

Acronym	*Full Form*
NGHM	National Green Hydrogen Mission
CAGR	Compounded Annual Growth Rate
FCEV	Fuel Cell Electric Vehicles
MTPA	Metric Tonnes Per Annum
CGD	City Gas Distribution
PNGRB	Petroleum And Natural Gas Regulatory Board
NG	Natural Gas
CNG	Compressed Natural Gas
PSA	Pressure Swing Adsorption
PNGRB	Petroleum And Natural Gas Regulatory Board
SMR	Steam Methane Reforming
GHG	Greenhouse Gases
API	American Petroleum Institute
PE	Polyethylene
HDPE	High Density Polyethylene
MDPE	Medium Density Polyethylene
CGS	City Gas Station
ROW	Right of Way
H2	Hydrogen
EU	European Union
PGC	Process gas chromatographs
PVC	Polyvinyl chloride
EPDM	Ethylene propylene diene monomer
ABR	Acrylonitrile butadiene styrene
NBR	Nitrile-butadiene rubber
SBR	Styrene-butadiene rubber
PTFE	Polytetrafluoroethylene
HENG	Hydrogen enriched Natural Gas