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The Techno-Economics of Hydrogen Pipelines

TECHNICAL BRIEF

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ABOUT THE TRANSITION ACCELERATOR

The Transition Accelerator (The Accelerator) exists to support Canada's transition to a net zero future while solving societal challenges. Using our four-step methodology, The Accelerator works with innovative groups to create visions of what a socially and economically desirable net zero future will look like and build out transition pathways that will enable Canada to get there. The Accelerator's role is that of an enabler, facilitator, and force multiplier that forms coalitions to take steps down these pathways and get change moving on the ground.

Our four-step approach is to understand, codevelop, analyze and advance credible and compelling transition pathways capable of achieving societal and economic objectives, including driving the country towards net zero greenhouse gas emissions by 2050.

1 UNDERSTAND the system that is being transformed, including its strengths and weaknesses, and the technology, business model, and social innovations that are poised to disrupt the existing system by addressing one or more of its shortcomings.

2 CODEVELOP transformative visions and pathways in concert with key stakeholders and innovators drawn from industry, government, indigenous communities, academia, and other groups. This engagement process is informed by the insights gained in Stage 1.

3 ANALYZE and model the candidate pathways from Stage 2 to assess costs, benefits, trade-offs, public acceptability, barriers, and bottlenecks. With these insights, the process then re-engages key players to revise the vision and pathway(s), so they are more credible, compelling, and capable of achieving societal objectives that include major GHG emission reductions.

4 ADVANCE the most credible, compelling, and capable transition pathways by informing innovation strategies, engaging partners, and helping to launch consortia to take tangible steps along defined transition pathways.

ABOUT THE AUTHORS

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TRANSITION ACCELERATOR

Adnan Khan is an Energy Systems Analyst at the Transition Accelerator working to help design pathways towards the establishment of a sustainable energy future. Adnan has a PhD in Material Science and Engineering and is passionate about working on renewable energy systems and contributing to the development of a future hydrogen economy. He has over eight years of industrial and academic experience leading research teams across the value chain of technology development and commercialization, driving innovation, and fostering collaboration among industry, government, and academia. He published over 35 articles in reputable scientific journals, has seven granted patents and hopes his work will lead to the spin-out of consortia led projects, create change on the ground to help drive Canada towards a net-zero future.

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LIST OF ABBREVIATIONS

ABBREVIATION	DEFINITION
AIH	Alberta Industrial Heartland, a region in Alberta which includes Edmonton, Strathcona, Fort Saskatchewan, Sturgeon, and Lamont counties
ATR	Autothermal Reforming
BEB	Battery Electric Bus
Blue Hydrogen	Hydrogen produced from natural gas with carbon capture and storage
CESAR	Canadian Energy Systems Analysis Research
CCS	Carbon Capture and Storage
CCSU	Carbon Capture, Storage and Utilization
CO_2	Carbon Dioxide
CRF	Capital Recovery Factor
C$	Canadian dollars
DTE	Drivetrain Efficiency
EOR	Enhanced Oil Recovery
EWMC	Edmonton Waste Management Centre
FCEB	Fuel Cell Electric Bus
GHG	Greenhouse Gas
GJ	Gigajoule (10^9 Joules)
Green Hydrogen	Hydrogen produced by water electrolysis using intermittent zero-carbon electricity generated from wind and solar facilities

Grey Hydrogen	Hydrogen produced from natural gas or coal
H_2	Hydrogen
HDV	Heavy-Duty Vehicle: Vehicles with a gross vehicle weight rating >= 15 metric ton or tonne
HFCE	Hydrogen Fuel Cell Electric
HFS	Hydrogen Fueling Station
HHV	Higher Heating Value
ICE	Internal Combustion Engine
IF	Installation Factor
LCOH	Levelized Cost of Hydrogen
LDV	Light-Duty Vehicle
LH_2	Liquid Hydrogen
MDV	Medium-Duty Vehicle
NG	Natural Gas
NWR	Northwest Redwater
O&M	Operations and Maintenance
PJ	Petajoule (10^{15} Joules)
SF	Scale Factor
SMR	Steam Methane Reforming
SUT	Single Unit Truck
TCI	Total Capital Investment
TIC	Total Installed Cost
UC	Uninstalled Cost

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Prairies Economic Development Canada / Développement économique Canada pour les Prairies

Natural Resources Canada / Ressources naturelles Canada

Canada

Alberta's Industrial Heartland

EMISSIONS REDUCTION ALBERTA

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EXECUTIVE SUMMARY

The future of a hydrogen economy will rely on developing infrastructure for low-cost distribution and delivery of hydrogen. To this end, pure hydrogen pipelines hold the most promise for large scale and low-cost transportation of hydrogen. Nonetheless the construction and installation of pipelines is a costly, complex, and time-consuming process that requires substantial demand for fuel movement to attract private investment.

The purpose of this 'technical brief' is to describe how to carry out techno-economic analyses for pure hydrogen pipelines, including their sizing, operating and cost estimating. The primary focus of this work is on the design and costing of pipelines transporting large volumes of hydrogen across large distances. However, the principles discussed here can be used to explore the cost of smaller, shorter pipelines to serve applications such as a fueling station or the blending of hydrogen into natural gas distribution systems.

The report draws on several previous studies to develop a model that can be used by students, engineers, scientists, or entrepreneurs to size, characterize and cost hydrogen pipeline technologies, conducting gas flow calculations, compression power requirement and associated costs.

Some key insights and highlights are as follows:

- Although natural gas is widely transported via pipelines; the design, construction, and operation of hydrogen pipelines are more challenging than most other gases and liquids due to hydrogen's low density, embrittlement challenges, and safety concerns.
- Lower strength steel and polyethylene pipelines are less prone to hydrogen attack and embrittlement than high pressure, high carbon steel; Therefore, most of the smaller distribution pipelines for natural gas in cities could be repurposed for hydrogen.
- Further research is needed to develop appropriate coatings, inhibitors, and odorants for protecting hydrogen pipelines from corrosion.
- The safety risks associated with hydrogen are greater than those with natural gas because of its large flammability range in air, small amount of energy required for ignition, and the invisibility of the flame.
- Even though hydrogen has only one third the volumetric energy density of natural gas, hydrogen flow in a pipeline can be significantly higher than that for natural gas/methane. Therefore, in the same pipeline can carry hydrogen at ~ 88% of the energy it can carry as natural gas/methane.
- Transporting hydrogen via pipelines is a relatively low-cost distribution option (<1 C$/$kg_{H2}$; <7 $/GJ) if done at scale at large scale i.e., 100s of t_{H2}/day to 1000s t_{H2}/day depending on distance. For short distances which don't require compressor stations along the length of pipeline, we can propose a rule of thumb: "A demand of ~1-1.2 t_{H2}/day/$km_{pipeline}$ is needed to drive economic viability".
- Pipelines need significant capital investment in millions of C$. Therefore, for an initial transition period where hydrogen demand is not enough to attract private investment, government support might be needed.

1 INTRODUCTION

In the transition to net-zero energy systems, hydrogen (H_2) is envisioned to play a major role as a zero-emission energy carrier in combination with electricity made with minimal or no greenhouse gas (GHG) emissions. Centralized green (from water electrolysis with renewable or nuclear power) or blue (from fossil fuels coupled to carbon capture and storage) H_2 production tends to be the lowest cost. However, the hydrogen must then be moved to where it will be used as a fuel for heavy / long distant transport or as a source for building or industrial heating. Therefore, for H_2 to develop to its full potential as an energy carrier, there must be well-developed H_2 transport infrastructure connecting supply to demand. Truck transport of compressed gaseous H_2 or of cryogenic liquid H_2 can move smaller amounts of gas (1 to 4 t_{H2}/truck), but the costs per km-kg H_2 are significant and would eliminate most applications for H_2 as a heating fuel. Pure H_2 pipelines hold the most promise large scale and low-cost deployment of H_2 as a zero-emission fuel. Transporting H_2 via pipelines can be an effective delivery method connecting central or distributed production sites to customers.

The transportation of H_2 via pipelines can be traced back to the late 1930s, but these were mainly short length process pipelines operating at low pressures within an industrial facility. There are ~2500 km of active H_2 pipelines in the United States today, and over 90% of these pipelines are located along the Gulf Coast primarily connecting major H_2 producers with well-established, long-term customers such as refineries and ammonia plants [2-4].

Similarly, Canada also has several hundred kilometers of process pipelines transporting H_2 inside facilities, like refineries, but built mainly on pipe racks above ground. A 48 km H_2 transmission pipeline connects the Air Products H_2 production facilities in Strathcona County near Edmonton to customers in Fort Saskatchewan [5]. The company also operates a hydrogen production facility, a 30-kilometer pipeline network and a liquefaction facility in Sarnia, Ontario [6].

In Europe, 1100 to 1,770 km of H_2 pipelines have been documented [2,7]. Since 1939, Germany has been using a 210 km pipeline carrying ~ 9000 kg_{H2}/hr in a 10-inch pipe at 20 bar [2,7]. The European H_2 backbone report released in 2020, estimates that a 48-inch pipeline would be able to transport ~1.9 x 10^6 t_{H2}/yr (13 GW using LHV) across Europe at a cost of ~0.07-0.23 €/kg/1000 km [8]. As we move ahead to develop a H_2 economy, it is important to analyze the challenges and costs associated with transporting pure H_2 in pipelines across long distances.

The purpose of this 'technical brief' is to describe how to design and estimate the capital, energy and operating cost of H_2 pipelines, with a particular focus on moving 10's to 100's to 1000's of t_{H2}/day as the backbone infrastructure in an emerging fuel H_2 economy. The document provides a 'beginner's guide' for engineers and scientists focused on calculating pipeline capacities using gas flow calculations, pressure drop, compression power and associated costs. Since it is well understood that many of the design, construction, and operational features of H_2 pipelines would be similar to natural gas, we first present details on how natural gas pipelines are designed, constructed, and operated.

In addition, we will also address the key differences and challenges that arise with transport of H_2 versus natural gas such as those related to volumetric energy density of H_2, compression, embrittlement, and safety. While the repurposing of natural gas pipelines could play an important role in the next energy transition, details on how best to do such a retrofit are not available to us, so are not provided here.

2 GAS PIPELINE SYSTEM

The natural gas pipeline distribution chain consists of different types of pipelines categorized depending on where they are used. They can be divided into:

- Gathering pipelines: These are typically small diameter pipelines that collect raw natural gas from wellheads in production fields and move it either to a processing plant or connect to the mainline transmission grid. The processing facility is used to remove impurities like water, carbon dioxide and sulfur that might corrode a pipeline [9,10]. It is estimated that Canada has ~250,000 km of these small diameter (4” to 12”) gathering pipelines [11].
- Transmission pipelines: These are large pipelines (typically 6-48 inches in diameter) that move gas long distances, often at high pressures (typically 10-120 bar) [12]. Canada has close to 120,000 km of transmission pipelines that move crude oil and natural gas within the country and across to the United States [11].
- Distribution pipelines: These are a system of smaller (typically 2-10 inches in diameter) pipes that deliver natural gas to small industrial plants and customers at lower pressures (2-10 bar) and there are about 450,000 km of distribution pipelines in Canada [10-12].
- Service Lines: These are the smallest pipelines (typically 0.5-2 inches in diameter) that deliver gas to residential customers at low pressure (~1 bar).

By law, pipelines that cross provincial or national borders (interstate) are federally regulated, and pipelines that are entirely within one province (intrastate) are regulated by the appropriate regulatory agency [11,13]. A future H_2 pipeline system would look like the schematic in **Figure 2.1**, whereby a combination of transmission and distribution pipelines would connect production sites to end users such as large ammonia plants, heat/power sites, residential customers and hydrogen fueling stations (HFS).

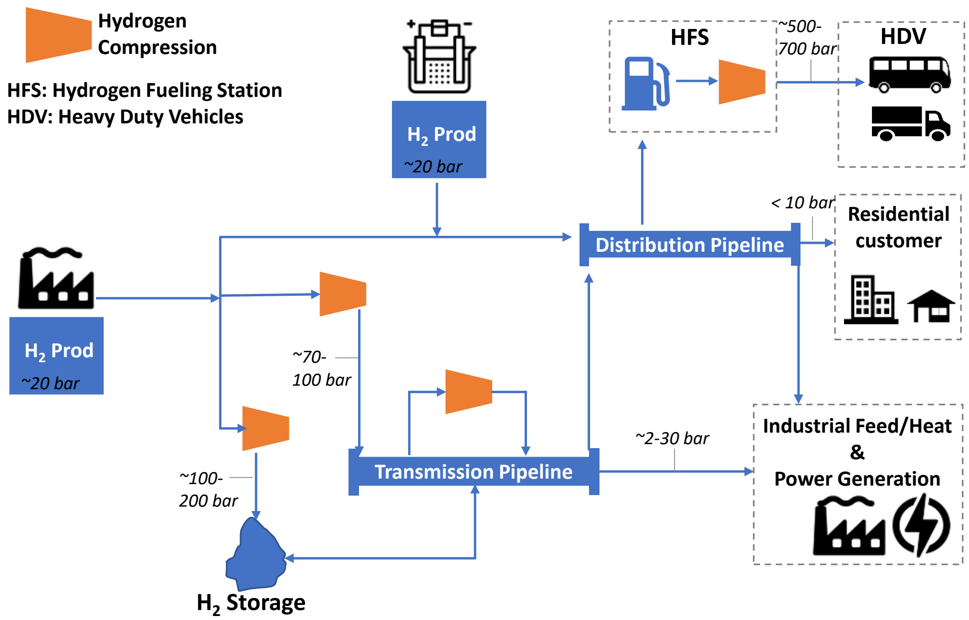

Figure 2.1. Schematic showing future H_2 gas pipeline transportation system.

2.1 How Gas Pipelines Work

Gas moves through pipelines as a result of pressure differential i.e., the gas flows from high pressure at inlet to lower pressure at outlet [10,12,14]. This pressure differential is created by compressors stations that are generally built every 100 to 500 km along the length of the pipeline, to boost the pressure that is lost through friction [8].

Compressors are driven by different types of engines such as reciprocating engines, gas turbines or electric motors which are also known as "prime movers". The selection of the compressor dictates the choice of the prime mover as well. For natural gas pipelines, typically centrifugal compressors driven by natural gas turbines are most commonly used.

The design and fabrication of centrifugal compressors for H_2 is very challenging due to its low molecular weight which means 3X higher impeller tip speeds are needed versus natural gas. While centrifugal H_2 compressors are being developed, reciprocating compressors will suffice for lower flow rates but suffer from reliability issues. The cost and efficiency of a pipeline system requires an optimization of pipe size, pipe material, compressor units, operating pressure, pipe length and few other parameters to match demand and reduce cost [15]. Pipeline companies use advanced simulation programs to carry out the design and optimization of pipeline systems.

During operation, pipeline operators monitor the flow of the gas and watch for any problems that might arise. Most systems on a pipeline, such as compressors, valves and regulators, can be remotely operated from a central control room, allowing operators to adjust flow rates or to isolate certain sections of a pipeline [10,12,14]. For a distribution network, operators also regulate flow and pressure in pipelines. When a regulator detects that the pressure is lower than a set point, it opens accordingly to allow more gas flow. Conversely, when pressure increases above a set point, the regulator will close to adjust.

The transmission pipeline network is connected to the distribution system via the city gate that brings the gas directly to homes and businesses [10,14]. City gate stations serve three purposes. First, they reduce the pressure in the pipeline network [10,14]. Secondly, an odorant (typically mercaptan for natural gas) is added to the gas, so leaks can be detected [10,14]. Finally, the gate station also measures gas flow rate to determine the amount being received by the utility [10].

2.2 Pipeline Construction and Installation

While the overall design of a H_2 pipeline network will be identical to a natural gas pipeline network as described above, there are several aspects related to construction, installation, and operation of H_2 pipelines that will differ versus natural gas pipelines. Some of these points are described below.

2.2.1 Pipeline Material

Pipelines can be made from a wide range of materials. **Figure 2.2** shows the relative contribution per distance travelled by natural gas pipelines of various types in the United States. Most gathering and transmission pipelines are made out of carbon steel or stainless steel with a diameter of 4-48 inches [3,16]. High-strength steels (above 100 KSI) which are often used in natural gas transmission pipelines are more susceptible to H_2 embrittlement, so the use of thicker, low-strength steels is sometimes recommended for H_2 pipelines [2,3,16]. On the other hand, distribution main and service pipelines are typically built using low-strength steel or high strength polyethylene (PE) and typically have a diameter of 0.5- 8 inches [3,16].

A recent study concluded that while permeation of H_2 through the walls of PE is 4-5 times greater than methane, the gas permeation loss is still very small and acceptable from both safety and economic points of view [3]. At the same time, lower strength steels such as API 5L A, B, X42, and X46 which are commonly used in distribution main lines are generally not susceptible to H_2 embrittlement under normal operating conditions [17,18]. Therefore, it should be possible to repurpose a significant fraction of the natural gas distribution pipeline network for transporting H_2.

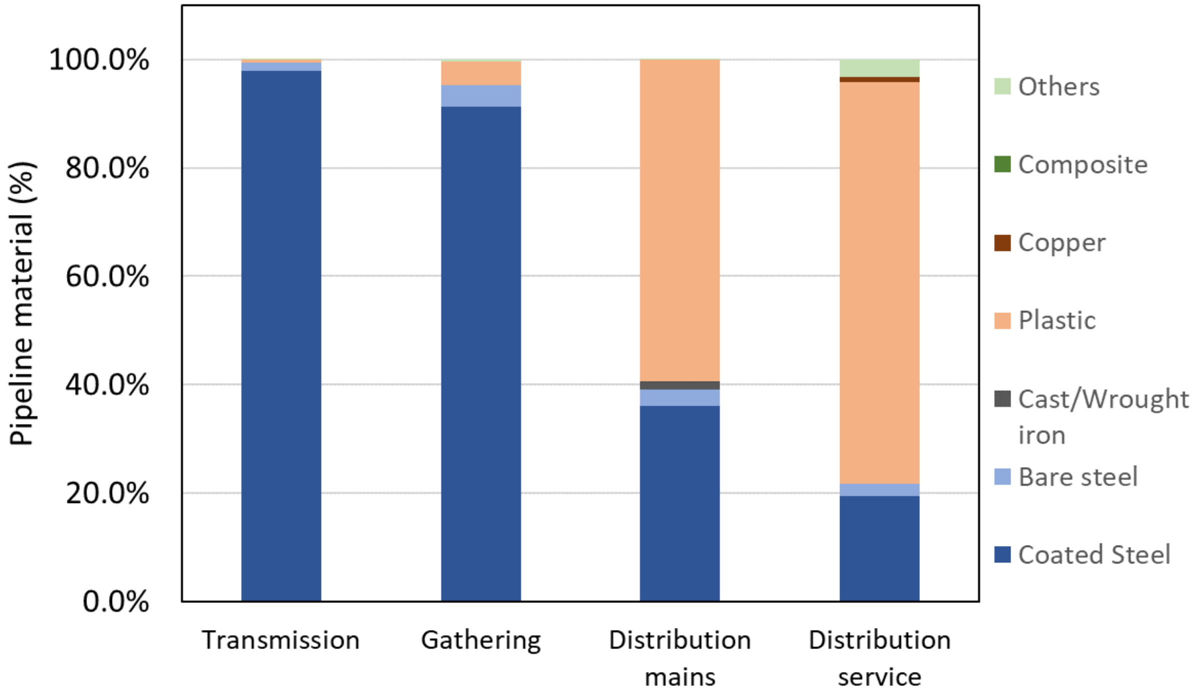

Figure 2.2. Pipeline material as a percentage of miles for gathering lines, transmission lines, distribution mains, and distribution service lines in the United States.

Source: Data taken from U.S. Department of Transportation, Pipeline and hazardous Materials Safety Administration, Reference [16].

2.2.2 Pipe Corrosion Protection and Coatings

Unprotected steel pipelines are susceptible to internal and external corrosion, and without proper corrosion protection every steel pipeline will eventually deteriorate. The three common methods used to control corrosion on pipelines [14]:

- Cathodic protection (CP): is a system used for the protection of steel pipelines since the 1930s. Corrosion in steel pipelines occurs naturally due to an electrical current that flows from a pipeline to surrounding soil. In its simplest form metal rods called anodes are connected near the pipeline to counteract the normal external corrosion that occurs on a metal pipeline, as shown in **Figure 2.3(a)** [19]. This can be used on steel pipelines irrespective of whether the pipe is used for natural gas or H_2.

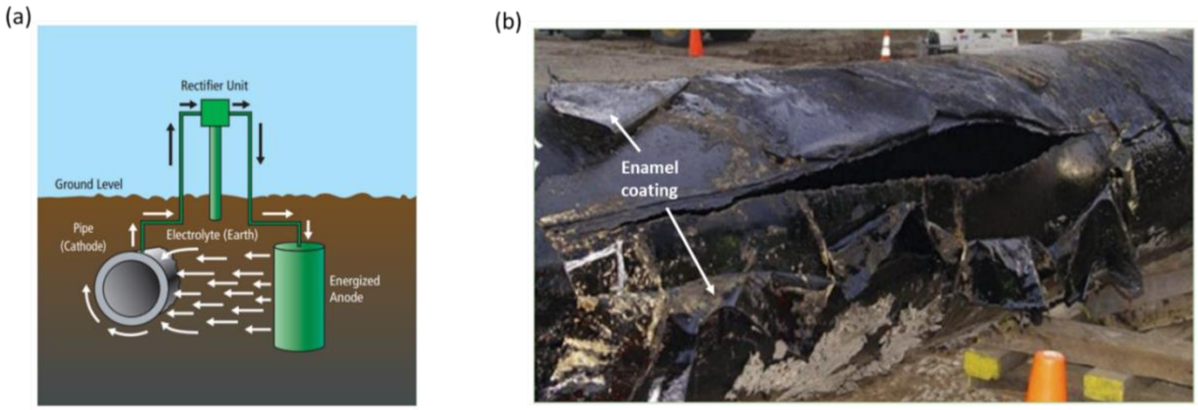

Figure 2.3. (a) Schematic of cathodic protection of steel pipelines. (b) Photo of Enbridge pipeline that failed in Michigan in 2010 showing the older enamel wrap coating installed.

Source: Adapted from References [14,19].

- Pipeline coatings: are used for defending against corrosion by protecting the bare steel from coming in direct contact with corrosive conditions. Most coatings are applied to the outer pipe wall and the most common coatings for natural gas pipelines are fusion bonded epoxy (FBE) or polyethylene heat-shrink sleeves [2,20,21]. Older pipelines may be uncoated or have coal tar or enamel wrap coating. **Figure 2.3(b)** is a picture showing the older enamel wrap coating on the Enbridge pipeline that had failed in Michigan in 2010 [14]. R&D efforts are underway to develop specialty materials for internal coating of pipelines and minimizing H_2 embrittlement [22,23].
- Corrosion inhibitors: are additives that can be added to the gas running through a pipeline to provide protection against internal corrosion. There have been many studies on using additive gases such as oxygen, carbonyl-sulfide (COS), ethylene (C_2H_4) and chlorotrifluoroethylene (CTFE) to protect steel from H_2 embrittlement [23]. There are many challenges and limitations with this approach arising from the combustibility, toxicity, and cost of the inhibitors [23]. This approach will also require an additional purification step depending on end use of H_2.

For natural gas transmission pipelines in the United states, it is estimated that ~96% of pipelines are wrapped/coated and cathodically protected against corrosion [3].

2.2.3 Pipeline Burial

Prior to putting a pipeline in the ground, clearing and grading activities are conducted to provide a reasonably leveled working surface as shown in **Figure 2.4(a)** [2]. Transmission pipelines are buried using a trenching method (**Figure 2.4(b)**), whereby a trench would be excavated to a depth that is usually guided by legal regulations. For example, the Canadian Standards Association's minimum depth of soil coverage requirement is 0.6 meters (24 inches), but Enbridge is using a minimum soil coverage depth of 0.9 meters (36 inches) for new pipeline projects [24].

These legal regulations might need to be revised for H_2 considering associated risks and engineering challenges. Other techniques such as boring and horizontal directional drilling (HDD) are used when trenching is not desirable or allowed such as when required to cross major paved roads, highways, railroads and rivers. [14]. HDD is frequently used where pipelines must cross rivers to reduce the environmental impact. The challenge with boring and HDD is that they might not be compatible with all soil types and there is a risk of drilling through hard-to-locate prior lines in the ground. An example of a gas pipeline that was cross bored though a sewer line is shown in **Figure 2.4(c)**.

Figure 2.4. (a) Bulldozer grading prior to pipeline burial. (b) Pipeline trenching operations. (c) Example of a problematic cross bore of a gas pipeline through a sewer line.

Source: (a & b) Adapted from Reference [2]. (c) Adapted from Reference [14].

2.2.4 Welding of Steel Pipelines

It is likely that welding procedures and leak testing would be more stringent for H_2 pipelines compared with natural gas pipelines. The is due to the small molecular size of H_2 versus natural gas which make it more susceptible to leaks. Typically all pipelines use welding wherever possible to connect sections of pipes into a pipeline [2,14]. To carry out the welding process, the pipe sections are lined up using special pipeline equipment called side booms that help in positioning until the welding process is done. Welding is usually carried out in multiple passes using manual, semiautomatic or automatic welding procedures. As part of the quality testing, each welder must pass qualification tests and each weld procedure must be approved for use. For higher stress pipelines over 6 inches in diameter, multiple levels of quality checks ensure the quality of the welding. Finally, all welds are inspected using radiological techniques (i.e., X-ray or ultrasonic inspection) to ensure they meet federally prescribed quality standards [2,14]. For H_2 pipelines, the strength, integrity of welds and associated quality checks are even more important as these welds are reported to be susceptible to H_2 embrittlement (more on this in Section 3).

2.3 Pipeline Operation and Maintenance

Natural gas pipelines usually outlast the market conditions/demand for which they were designed. Improved operation and maintenance procedures now mean the typical lifetime of transmission pipelines is 30-50 years. Pipeline companies use advanced software to determine if the system is running smoothly, detect leaks and prioritize maintenance and repair schedules based on computerized analysis. There are specialized inspection devices to help monitor the system with the most commonly used referred to as 'pigging technique' in which instruments called 'smart pigs' look for potential problems such as deformations, cracks and corrosion. The existing concepts and equipment used for operation and maintenance of natural gas pipelines can be adjusted to the necessities of H_2 pipeline transport with minor alterations [25]. For example, a H_2 pipeline built in 1996 in the United States was inspected in 2017 and 2019, with correspondingly designed pigs [25]. At a pressure of 20 bar and a flow of 13,000 Nm^3/h, the tools were able to move safely, and the inspection was completed with a 100% sensor cover [25]. Nonetheless, some challenges related to the operation and maintenance of H_2 pipelines are highlighted below.

2.3.1 Safety

The safe operation of H_2 pipelines will be more challenging than natural gas pipelines. As H_2 is the smallest molecule known, it is difficult to contain and leak management is more complex. H_2 in dry air has a large flammability range ranging from 4% (Lower Flammability level) to 76 % (Upper flammability level) at 1 bar and 20 °C [4,26]. Furthermore, H_2-air mixtures are extremely easy to ignite requiring only 0.017 mJ ignition energy compared to 0.28 mJ for methane [27,28]. Finally, H_2 burns in air with a pale blue, almost invisible flame which increases the risk of injury if the H_2 catches on fire.

2.3.2 Gas velocity

One challenge in transporting H_2 energy is its low volumetric energy density of 10.8 MJ/Sm^3 (LHV) which is approximately one-third that of methane ~35.8 MJ/Sm^3 (LHV) [29]. Therefore, for a given pipeline to carry the same amount of H_2 energy as methane, the volumetric flow rates must be significantly higher at the same operating pressure and temperature. This will be discussed in more detail in section 4.2. However, operating pipelines at higher flow rates comes with own set of challenges such as increased pressures, compression energy requirement, chances of leaks and embrittlement to name a few.

2.3.3 Valves

Valves are devices that are used to control, regulate, or direct flow of gas in a pipeline. For large diameter pipelines, these valves are typically motor operated valves (MOV). MOV can be operated locally by pipeline personnel, remotely from a control room, or automatically if a certain incident occurs. It is expected that valves used for H_2 pipelines will be significantly more costly that those used in natural gas pipelines due to tighter tolerances and use of exorbitant materials for construction [2]. Furthermore, with the inherent safety risks associated with H_2, valves would also require more frequent inspection, servicing and replacement compared to a natural gas pipeline. Considering these challenges, substantial R&D has been directed toward the development of effective valves for H_2 pipelines.

2.3.4 Odorization

Natural gas pipeline systems carry out an odorization step at the city gate stations before the gas is distributed to residential customers. In this step, an odorant (typically mercaptan) is added to the natural gas giving it a smell of rotten eggs and therefore it is easier to detect leaks [14]. Like natural gas, H_2 is also odorless and will require the addition of an odorant at the city gate stations. However, at this time, the odorant for H_2 has yet to be approved and defined by regulation. This will need to be done before there is widespread deployment of H_2 for space and water heating [3].

3 HYDROGEN GAS EMBRITTLEMENT

While the concept of H_2 embrittlement was introduced in section 2.2.1, it is important to address the concept in more detail since it is a key challenge for transporting H_2 in steel pipelines at high pressures [17,18]. H_2 embrittlement leads to decrease in ductility of the steel and its tensile strength due to the absorption and diffusion of H_2 atoms or molecules [30]. Molecules of H_2 may dissociate at the surface of steel pipe into two H atoms which may then diffuse deep into the steel. Regardless of the form, the H atoms or molecules coalesce to form small bubbles at metal grain boundaries as shown in **Figure 3.1(a)** [30]. These bubbles cause stress, intergranular cleavage that can eventually lead to cracking and rupture as shown in **Figure 3.1(b)** [17]. During operation, significant pressure fluctuations accelerate the embrittlement process, with reported fatigue crack growth rates an order of magnitude higher [31]. Equally important, optimization and quality check of weld joints is paramount with these joints being most prone to H_2 embrittlement [32].

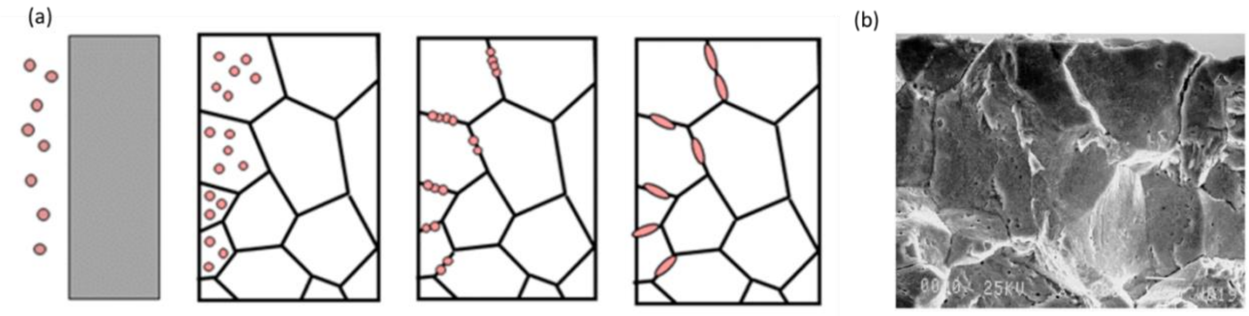

Figure 3.1. (a) Schematic of H_2 embrittlement process in carbon steel. (b) Scanning electron microscopy (SEM) image revealing intergranular cleavage, characteristic of H_2 embrittlement.

Source: Adapted from References [30,34].

It is understood that H_2 embrittlement is more problematic in high strength steels (tensile strength > 145 ksi) with high manganese and/or carbon content. Current data suggests that lower strength/grade steels (X52 or below) are less susceptible to H_2 embrittlement [2,17]. However, the use of lower grade steel means lower operating pressures are possible or that the wall thickness will need to be increased to accommodate the high operating pressures of transmission pipelines. Another key feature related to H_2 embrittlement is the vulnerability of some weak welds and hard spots to H_2 attack [33]. Therefore, the welds must be defect free and the weld heat affected zones must match mechanical and properties of pipeline. In this regard, the current integrity management programs that are appropriate for natural gas pipelines will have to be adjusted for H_2 pipelines [3].

4 GAS PIPELINE HYDRAULICS

This section will describe gas pipeline hydraulics with focus on transporting H_2. Specifically, it describes how to conduct gas flow calculations based on important parameters such as inlet and outlet pressures, gas velocity, pipe length and pipe roughness. The equations and methodology used in our analysis are adapted from Sashi Menon's book on gas pipeline hydraulics [35].

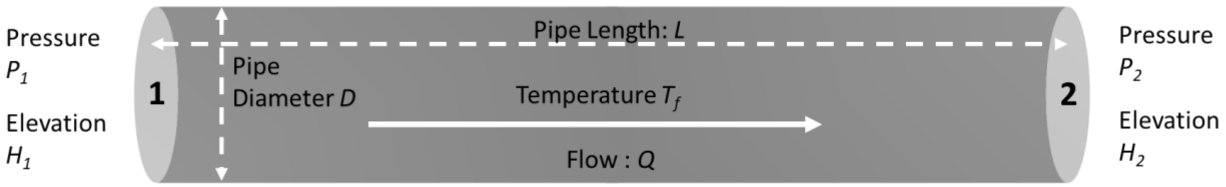

Figure 4.1. Steady state flow in a gas pipeline.

Source: Adapted from Reference [35].

Consider gas flow from point 1 to point 2 in a straight cylindrical pipe as shown in **Figure 4.1**. If $P_1 = P_2$, there would be no "driving force" for the gas to flow. Gas flows primarily due to pressure difference between point 1 and 2 and only partly due to the elevation difference (H_2 – H_1) [35]. As gas flows through the pipe, it encounters a drop in pressure due to friction between the flowing gas and pipe. Therefore, the higher the pipe roughness and length, the higher the pressure drop. There are additional frictional losses due to elbows, branching, control valves, etc. The velocity of the gas (V), which is proportional to the volumetric flow rate (Q), also changes depending upon the cross-sectional area (A) of the pipe and the pressure and temperature (T_f) of the gas [35].

Using Bernoulli's equation, engineers have developed an equation for calculating the pressure drop in a gas pipeline, considering the pipe diameter, length, elevation difference, gas flow rate, gas specific gravity and gas compressibility. This basic equation is referred to as the Fundamental Flow Equation, also known as the General Flow equation, as shown in Eq. (1). Several other flow equations such as Panhandle A, Panhandle B and Weymouth equations have been developed by the gas pipeline industry, but the General Flow equation is the most utilized one. Since the volume flow rate Q can vary with the gas pressure and temperature, we must refer to some standard volume flow rate. Thus, the gas flow rate Q will be referred to as standard m^3/day (SCMD) in SI units.

$$Q = 1.1494 \times 10^{-3} \left(\frac{T_b}{P_b}\right)\left[\frac{(P_1^2 - e^s P_2^2)}{G T_f L_e Z f}\right]^{0.5} D^{2.5} \qquad (1)$$

Q is is gas flow rate in Sm^3/day.

L is pipe length in km.

s is elevation adjustment parameter and is dimensionless as defined by Eq. (2).

L_e is Equivalent pipe length in km as defined by Eq. (3).

D is inside pipe diameter in mm.

P_1 is inlet pressure in kPa (Absolute pressure not gauge pressure)

P_2 is outlet pressure in kPa (Absolute pressure not gauge pressure)

P_b is base pressure in kPa (101.352 kPa).

T_b is base temperature in K (288.706 K).

T_f is average flowing temperature of gas in K.

G is specific gravity (For Hydrogen, G = 0.0696)

Z is the compressibility factor at average temperature and pressure.

f is friction factor and is dimensionless.

$$s = 0.0684G\left(\frac{H_2 - H_1}{T_f Z}\right) \qquad (2)$$

Where H_1 and H_2 are inlet and outlet elevation in meters.

$$L_e = L\left(\frac{e^s - 1}{s}\right) \qquad (3)$$

The General Flow Equation can be used to calculate flow rates in a gas pipeline, given the inlet (P_1) and outlet (P_2) pressures. Alternatively, it can be used to calculate pressure drop for a given flow rate. In the analysis presented in this report, we focus on the former by targeting a fixed outlet velocity (V_2: Eq 7) and recalculating outlet pressure P_2 and flow rate Q, accordingly. The methodology is summarized in **Figure 4.1**.

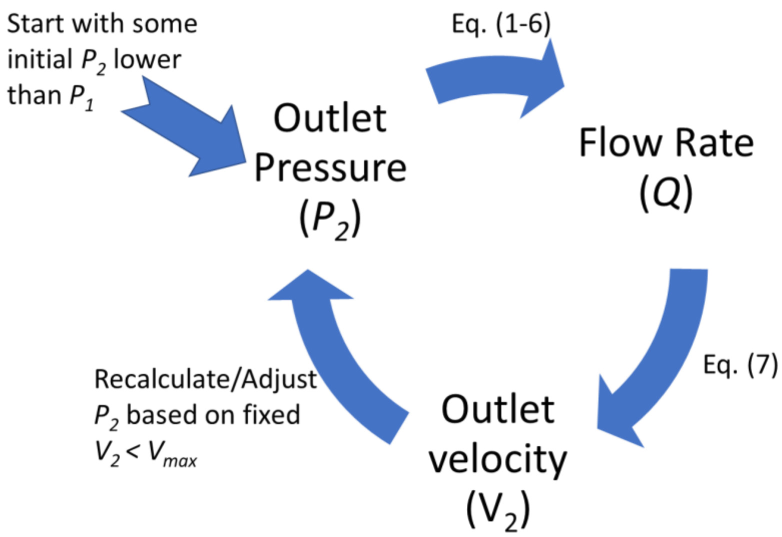

Figure 4.2. Methodology used for H_2 flow calculations in a pipeline.

It is important to note that Eq. (1) assumes isothermal gas flow in the pipeline. The general flow equation leads to some interesting observations on gas flow in pipelines:

- Gas flow rate (*Q*) is proportional to the square root of difference in squares of the upstream and downstream pressures, or $\sqrt{(P_1^2 - P_2^2)}$. This means that the pressure gradient for gas flow is slightly curved, compared to a linear pressure drop for liquid flow.
- Gas flow rate (*Q*) is proportional to the pipe diameter (*D*) raised to power 2.5. Therefore, an increase in pipe diameter leads to an increase in pipe capacity or possible flow rates.
- Gas flow rate (*Q*) is inversely proportional to square root of the gas gravity (*G*), compressibility factor (*Z*), pipe length (*L*) and gas flow temperature (T_f). Any increase in these parameters leads to a decrease in gas flow rates.

4.1 Key Parameters for Calculating Hydrogen Flow in Pipelines

1) **Compressibility factor and average pressure:** The compressibility factor (Z) of a gas accounts for the deviation of gas from ideal gas behavior. Typically, Z = 0.98-1.3 for H_2 in the pressure and temperature range examined in this report. Z can be determined using the CoolProp excel plugin or other applications such as NIST REFPROP. The average pressure (P_{avg}) can be calculated using Eq. (4):

$$P_{avg} = \frac{2}{3}\left(\frac{P_1^3 - P_2^3}{P_1^2 - P_2^2}\right) \qquad (4)$$

P_1 and P_2 are inlet and outlet pressures, respectively.

2) **Friction factor:** The flow through a pipeline may be classified as laminar, turbulent or transitioning from laminar to turbulent depending upon the value of a dimensionless parameter called the Reynolds number (Re) [36]. The flow in a gas pipeline is laminar when the Re is below 2000 while turbulent flow is said to exist when the Re is greater than 4000. When the Re is between 2000 and 4000, the flow is undergoing transition. In practice, most gas pipelines operate at flow rates that produce high Reynolds numbers, and therefore in the turbulent flow regime. Re depends upon gas properties, pipe diameter and flow velocity and is defined as shown in Eq. (5):

$$Re = \frac{V_{avg}\, D\rho_{avg}}{\mu} \qquad (5)$$

V_{avg} is average gas velocity in m/s.

D is inside pipe diameter in m.

ρ_{avg} is average gas density in kg/m^3.

μ is gas viscosity in kg/m.s.

The friction factor (f) in the General Flow Equation is referred to as the Darcy friction factor and depends upon the internal condition (rough or smooth) of the pipe wall and whether the flow is laminar or turbulent [36]. One option of calculating f is graphically from the Moody friction factor diagram, first presented by L.F. Moody in his 1944 paper in the Transactions of the ASME [37].

For turbulent flow, the Colebrook-White equation can be used to calculate the friction factor in a pipeline with roughness (ε), using Eq. (6) [35]:

$$\frac{1}{\sqrt{f}} = -2log_{10}\left(\frac{\varepsilon}{3.7\,D} + \frac{2.51}{Re\sqrt{f}}\right) \qquad (6)$$

The Colebrook-white equation cannot be solved explicitly, therefore an iterative solution is required using an initial value of (f) and Re.

3) **Velocity of gas in Pipeline:** Under steady state conditions, the velocity of gas flow can be calculated using the volumetric flow rate (Q) and pipe cross sectional area (A). However, due to pressure variation in a gas pipeline (due to frictional losses), the average velocity varies and is a function of the flow rate, gas compressibility factor, pipe diameter, pressure, and temperature, as indicated in Eq. (7) [35]. It can be seen from the velocity equation that the higher the pressure, the lower the velocity and vice versa.

$$V = 14.734\left(\frac{P_b}{T_b}\right)\left(\frac{ZT}{P}\right)\left(\frac{Q}{D^2}\right) \qquad (7)$$

V is gas velocity in m/s.

Q_b is gas flow rate in Sm^3/day.

D is inside diamter of pipe in mm.

P_b is base pressure in kPa (101.352 kPa).

T_b is base temperature in K (288.706 K).

P is gas pressure in kPa.

T is gas temperature in K.

G is Gas gravity and is dimensionless.

Z is compressibility factor at pipeline conditions and is dimensionless.

4) **Erosional Velocity**: The erosional velocity represents the upper limit of gas velocity in a pipeline [35]. Higher velocities can cause erosion of the pipe wall over a long time. The erosional velocity V_{max} may be calculated approximately using Eq. (8).

$$V_{max} = 100\sqrt{0.05131\frac{ZRT}{GP}} \qquad (8)$$

V_{max} is erosional velocity in m/s.

P is gas pressure in kPa.

T is gas temperature in K.

Z is compressibility factor at pipeline conditions and is dimensionless.

R is ideal gas constant in (8.314 kPa.m^3/kg.mol.K)

5) **Pipeline capacity**: Once the flow rate (Sm^3/day) is calculated using Eq. (1), the design capacity (kgH_2/day) can be calculated using Eq. (9).

$$Capacity_{pipe}\left(\frac{kgH_2}{day}\right) = Q\left(\frac{Sm^3}{day}\right) * 0.0834\left(\frac{kgH_2}{Sm^3}\right) \qquad (9)$$

4.2 Energy Content of Hydrogen versus Natural Gas Pipeline

An important topic is the energy that can flow in a pipeline used to transport natural gas versus H_2. Since the primary component of natural gas is methane, we demonstrate the difference in pipeline energy while transporting methane versus H_2. While H_2 has a high energy density per unit mass (120 MJ/kg) versus methane (50 MJ/kg), the challenge arises due to its low volumetric energy density (10.78 MJ/m^3) which is ~ 3.29 times lower than methane (35.5 MJ/m^3) [29]. In other words, to ensure the same energy content in the pipeline, H_2 flow rates will have to be 3.29 times higher than methane. At any given pressure and temperature, the maximum flow rates in a pipeline are limited by the erosional velocity of the gas. The erosional velocity as explained earlier depends on gas properties such as compressibility factor and specific gas gravity. At typical transmission pipeline operating pressures of 70-100 bars, the erosional velocity of H_2 can be ~2.91 times higher than methane. Thus, maximum flow rates of H_2 can be 2.91 times higher than methane. Therefore, the maximum energy density of a H_2 pipeline is limited to ~ 2.91/3.29 = 88.4% of energy content of a methane pipeline. The calculation has been summarized in **Table 4.1**.

Table 4.1. Energy content of pipeline carrying H_2 versus methane.

	Methane	Hydrogen
LHV (MJ/kg)	50	120
LHV (MJ/m^3)	35.5	10.78
Required flow rate (m^3/s) to get same energy flowing through pipeline	X	= 35.5/10.78 = 3.29X (Required)
Erosional velocity (m/s) at 70 bar inlet pressure and 15 °C	17.1	49.9
Maximum flow rate (m^3/s) limited by erosional velocity	X	= 49.9/17.1 = 2.91X
Max Energy content (MJ)	Y	=2.91X/3.29X = **88.4% Y**

It is important to highlight that the higher flow rates needed for H_2 will result in higher compression energy. Since compression power depends on molar flow rate, it takes about three times as much energy to compress a MJ's worth of energy if you supply it as H_2 than if you supply it as natural gas. This was described in more detail in Transition Accelerator's technical brief on H_2 compression.

5 PIPELINE COST CALCULATIONS

The ideal time for minimizing the cost of gas transport via a pipeline is during initial design and construction, where gas flow calculations, project demand and other limitations are combined to optimize pipeline size, compressor units, flow rates, operating pressures etc. The levelized cost of a H_2 pipeline system ($LCOH_{pipe-system}$) consists of both the levelized cost of H_2 from pipeline ($LCOH_{pipe}$) and levelized cost of H_2 from the compressor stations ($LCOH_{comp}$) as shown in Eq. (10). The LCOH can be further broken down into the Capital expenditure ($Capex$), non-energy operating expenditure ($Non - Energy\ OPEX$) and Energy operating expenditure ($Energy\ OPEX$) as shown by Eq. (11-13).

$$LCOH_{pipe-system} = LCOH_{pipe} + LCOH_{comp} \quad (10)$$

$$Capex_{pipe-system} = Capex_{pipe} + Capex_{comp} \quad (11)$$

$$Non - Energy\ OPEX_{pipe-system} = Non - Energy\ OPEX_{pipe} + Non - Energy\ OPEX_{comp} \quad (12)$$

$$Energy\ OPEX_{pipe-system} = Energy\ OPEX_{comp} \quad (13)$$

The levelized cost of H_2 from compression ($LCOH_{comp}$) was discussed in detail in Transition Accelerator's technical brief on H_2 compression. Therefore, the following sections will breakdown the calculations on levelized cost of H_2 from the pipeline ($LCOH_{pipe}$).

5.1 Pipeline Capital Costs

The costs associated with building pipeline infrastructure can be separated into three groups

- **Total Installed Costs:** The total installed cost for various pipelines (TIC_{pipe}) were developed from historical cost data for natural gas pipelines in the US and summarized in the HDSAM model developed by Argonne National laboratory [38]. The equations, which are used in the delivery models, are summarized in **Table 5.1** below. In each of the equations there is a multiplication factor of 1.1 to adjust for the higher costs anticipated for a H_2 pipeline. The increased costs are due to: (1) more stringent inspections of the welds, and (2) leak-free seals on the isolation and control valves [39]. These cost correlations can be divided into four categories i.e., material cost, labor cost, right of way cost and miscellaneous cost as shown in Eq. (14) and assuming that H_2 embrittlement will not be an issue in steel pipelines.

$$TIC_{pipe} = Material\ cost + Labor\ cost + Miscellaneous\ cost + Right\ of\ way\ cost \quad (14)$$

Table 5.1. Material, labor, right of and miscellaneous cost correlations in 2009 US$ from HDSAM model.

Component	Equation
Transmission Pipeline Material	1.1 * 63027*exp(Diameter, in.*0.0697) * (Length, miles)
Transmission Pipeline Labor	1.1 * ([-51.393 * (Diameter, in.)^2 + 43,523 * (Diameter, in.) + 16,171] * (Length, miles))
Transmission Pipeline Miscellaneous	1.1 * ([303.13 * (Diameter, in.)^2 + 12,908 * (Diameter, in.) + 123,245] * (Length, miles))
Transmission Pipeline Right-of-Way	([-9E-13 * (Diameter, in.)^2 + 4,417.1 * (Diameter, in.) + 164,241] * (Length, miles))
Distribution Pipeline Material	Same as Transmission for pipe < 8-inch diameter; 50% of transmission for pipe >= 8-inch diameter
Distribution Pipeline Labor	Same as Transmission Pipeline but add 70,000 US$/mile for pavement removal and replacement.
Distribution Pipeline Miscellaneous	Same as Transmission Pipeline
Distribution Pipeline Right-of-Way	Same as Transmission Pipeline
Service Pipeline Material	Same as Distribution Pipeline
Service Pipeline Labor	Same as Distribution Pipeline
Service Pipeline Miscellaneous	Same as Distribution Pipeline
Service Pipeline Right-of-Way	Same as Distribution Pipeline

- **Total capital Investment:** Once the TIC_{pipe} is calculated, the total capital investment of pipeline (TCI_{pipe}) can be determined by adding the indirect costs as shown in Eq. (15). TCI is the CAPEX at the beginning of a project and can occur over several years depending on how long it takes to design & procure equipment, deliver it to a project site, and construct the project.

$$TCI_{pipe}\ (Capex\ of\ pipeline) = TIC_{pipe} + Indirect\ costs\ (40\%\ of\ TIC) \quad (15)$$

- **Indirect costs**: The simplest way to determine indirect costs is by calculating it as a percentage of the TIC. The indirect costs used in this technical brief are based on established literature (Source: HDSAM), and are detailed below:
  - **Site preparation = 5% of TIC**; Includes the purchase of land; 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.
  - **Engineering & Design = 10% of TIC**; Includes salaries and overhead for the engineering, drafting, and project management personnel on the project.
  - **Project Contingency = 10% of TIC**; 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, and unexpected price increases.
  - **Permitting = 3% of TIC**; 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 where the costs borne by one facility may not translate well into another facility. However, because of the potential for delay, re-design, and other considerations, permitting costs should be included in the overall cost assessment.

5.2 Pipeline Operating Costs

The costs associated with pipeline operations (OPEX) include:

- **Energy/Electricity OPEX:** There are no energy costs associated with the pipeline directly but are included in $LCOH_{comp}$, in the cost of energy to run the compressor stations.

- **Non-energy OPEX:** $Non-energy\ OPEX_{pipe}$ costs found in literature (Source: HDSAM) include labor costs and other fixed operation and maintenance costs as shown in Eq. (16).

$$Non-energy\ OPEX_{pipe}\left(\frac{\$}{yr}\right) = Total\ labor_{pipe}\left(\frac{\$}{yr}\right) + Fixed\ O\&M_{pipe}\left(\frac{\$}{yr}\right) \quad (16)$$

  - Total labor cost:

$$Total\ labor_{pipe}\left(\frac{\$}{yr}\right) = Direct\ labor_{pipe}\left(\frac{\$}{yr}\right) + Indirect\ labor_{pipe}\left(\frac{\$}{yr}\right) \quad (17)$$

    - Direct labor cost:

$$Direct\ labor_{pipe}\left(\frac{\$}{yr}\right) = Annual\ hours\left(\frac{hours}{yr}\right) * Labor\ rate\left(\frac{\$}{hour}\right) \quad (18)$$

$$Annual\ labor\ hours\left(\frac{hr}{yr}\right) = 8320 * \left(\frac{x}{100{,}000}\right)^{0.25} \quad (19)$$

where x = average pipeline use (kg H_2/day) and Labor rate = 49.6 C$/hr (2019). (Source: HDSAM)

- Indirect labor cost:

$$Indirect\ labor_{pipe}\left(\frac{\$}{yr}\right) = Direct\ labor_{pipe}\left(\frac{\$}{yr}\right) * Indirect\ labor\ factor\ (\%) \quad (20)$$

$Indirect\ labor\ factor = 50\%$; used to consider the cost of overhead (i.e., head office, personnel)

- Fixed O&M costs: All non-labor fixed O&M costs ($/yr) are calculated as a fraction of the TCI to reflect that the larger and more complex, and therefore more expensive, projects have higher upkeep costs throughout the project life. For transmission pipelines this accounts for 2.6% of TCI and can be broken down into:
  - Insurance = 1% of TCI_{pipe}
  - Property tax = 1% of TCI_{pipe}
  - Licensing and permitting = 0.1% of TCI_{pipe}
  - Operating, maintenance and repairs = 0.5% of TCI_{pipe}

$$Fixed\ O\&M_{pipe}\left(\frac{\$}{yr}\right) = Insurance\left(\frac{\$}{yr}\right) + Prop\ Tax\left(\frac{\$}{yr}\right) + Permits\left(\frac{\$}{yr}\right) + O\&M\left(\frac{\$}{yr}\right) \quad (21)$$

5.3 Pipeline Levelized Cost

The simple definition for the Levelized cost of hydrogen for pipeline transport ($LCOH_{pipe}$) is as follows:

$$LCOH_{pipe}\left[\frac{\$}{kgH_2}\right] = \frac{\left(Annualized\ capex_{pipe}\left[\frac{\$}{year}\right] + Non - energy\ OPEX_{pipe}\left[\frac{\$}{year}\right]\right)}{\left(Availability_{pipe}\ [\%] \times Capacity_{pipe}\left[\frac{kgH_2}{day}\right] \times 365\left[\frac{days}{year}\right]\right)} \quad (22)$$

where,

$$Annualized\ Capex_{pipe}\left[\frac{\$}{year}\right] = TCI\ _{pipe}(\$) * Capital\ recovery\ factor\ (CRF) \quad (23)$$

$$CRF = \frac{i\,(1+i)^n}{(1+i)^n - 1};\ (i - Discount\ rate\ (\%);\ \ n - Pipe\ lifetime)$$

- The annualized TCI converts the capital investment, which usually occurs at the beginning of the project lifecycle, into an annual expenditure so it can be compared equitably with other annual expenditures such as non-energy OPEX.

- Availability is the fraction of the year the asset (pipeline in this case) can operate. When multiplied with the pipeline's design capacity, it determines how much H_2 can be transported in a day. We assume that large transmission pipelines only need to be taken offline for maintenance for few weeks of the year or any unplanned outage i.e., ~ 10%, therefore availability = 100%-10% = 90%. All economic assumptions used to calculate $LCOH_{pipe}$ are summarized in **Table 5.2**.

Table 5.2. Detailed economic assumptions for calculating pipeline levelized cost.

Factor	Value / Conversion factor	Notes
Exchange rate	0.75 US$/C$	Source: 2019 average
Inflation Rate	e.g., CAPEX from 2007 to 2019 = 619.2 / 525.4 = 1.179	Source: CEPCI – Plant Cost Index for CAPEX/Equipment (US$) 2009 = 521.9; 2013 = 567.30; 2019 = 619.2
Discount Rate	8%	Discount rate = weighted average cost of capital (WACC)
Pipe Lifetime	50 years	Source: HDSAM
Electricity cost	0.11 C$/kWh$_e$	Rate Alberta Industrial Electricity in Alberta; Source: NRCAN
Availability	90%	Assumed
Labor Rate (C$/hr)	49.6	Source: HDSAM

6 CASE STUDY: A 1500 KM TRANSMISSION PIPELINE

In this example we will demonstrate detailed gas flow and cost calculations of a 1500 km transmission pipeline. The costs are calculated for a 36-inch steel pipeline with an inlet diameter (D) of 895.3 mm. The inlet pressure will be taken at 70 bar, outlet gas velocity at 35 m/s, and compressor stations will be assumed to be placed every 500 km along the pipeline, assuming pressure outlet from compressors at 70 bar. A reciprocating compressor with compression ratio per stage (x) of ~2.1, isentropic efficiency (η_{isen}) of ~80% and motor efficiency ~95% is considered for compression.

6.1 Case study: Input parameters

The detailed assumptions for each step of the analysis are listed in **Tables 6.1** and **6.2**.

Table 6.1. Summary of parameters used for gas flow calculations.

Factor	Value	Notes/Reference
Total distance (km)	1500	Assumed
Pipe Length (km)	500	Assumed
Inlet pressure (bar)	70	Based on typical transmission pipelines
Outlet gas velocity (m/s)	35	Assumed
Pipe roughness (mm)	0.0178	Based on private discussions.
Base Temperature (K)	288.71	[35,36]
Base pressure (kPa)	101	[35,36]
Flow temperature (K)	288.15	Assumed
Elevation difference (m)	100	Assumed
H_2 gas gravity	0.0696	[40]
H_2 viscosity (kg/m.s)	0.0000087	[41]

Table 6.2. Summary of parameters used for inlet compressor power calculations.

Factor	Value	Notes/Reference
Suction pressure of inlet compressor (bar)	20	Based on outlet pressure of SMR H_2 plant.
Discharge pressure of inlet compressor (bar)	70	= Inlet pressure of pipeline
T_{suc}: Suction temperature (K)	293.15	Assumed
η_{isen} (%)	80	Refer to TA technical brief on H_2 compression
Compression ratio/stage (x)	2.1	Refer to TA technical brief on H_2 compression
Maximum compressor size (kW)	16,000	Refer to TA technical brief on H_2 compression

6.2 Case study: Gas flow calculations

Table 6.3. Gas flow calculations for a 36-inch pipeline operating at maximum capacity with pipe length of 500 km.

Steps	Calculation	Notes
P_{avg}	$= \frac{2}{3}\left(\frac{70^3 - 28^3}{70^2 - 28^2}\right) = 52$ bar Where P_1 = 70 bar and P_2 = 28 bar	$P_{avg} = \frac{2}{3}\left(\frac{P_1^3 - P_2^3}{P_1^2 - P_2^2}\right)$; P_2 was recalculated by forcing outlet velocity = 35 m/s
Z	= 1.031 At assumed flow temperature and calculated P_{avg}.	Using CoolProp excel plugin

V_{max}	$= 100\sqrt{0.05131\frac{(1.031 * 8.314 * 288.15)}{(0.0696 * 7000)}}$ $= 51.01\ m/s$	$V_{max} = 100\sqrt{0.05131\frac{ZRT}{GP}}$
$Re\ and\ f$	$Re = \frac{35 * 0.895 * 4.58}{0.0000087} = 1.65 * 10^7$ f = 0.0094 (Calculated iteratively using f =1 as starting value)	$Re = \frac{V_{avg}\ D\rho_{avg}}{\mu}$ $\frac{1}{\sqrt{f}} = -2\log_{10}\left(\frac{\varepsilon}{3.7\ D} + \frac{2.51}{Re\sqrt{f}}\right)$
$s\ and\ L_e$	$s = 0.0684 * 0.0696\left(\frac{100}{288.15 * 1.031}\right) = 0.0017$ $L_e = 500\left(\frac{e^{0.0017} - 1}{0.0017}\right) = 500.43\ km$	$s = 0.0684G\left(\frac{H_2 - H_1}{T_f Z}\right)$ $L_e = L\left(\frac{e^s - 1}{s}\right)$
Q	$= 1.1494 * 10^{-3}\ *$ $\left(\frac{288.7}{101}\right)\left[\frac{(7000^2 - e^{0.0016}2800^2)}{0.0696 * 288.15 * 500.4 * 1.031 * 0.009}\right]^{0.5} 895.3^{2.5}$ $= 51{,}255{,}602.23\ \frac{Sm3}{day}$ = **51.25 MMSCMD**	$Q = 1.1494 * 10^{-3}$ $* \left(\frac{T_b}{P_b}\right)\left[\frac{(P_1^2 - e^s P_2^2)}{GT_f L_e Zf}\right]^{0.5} D^{2.5}$
V_{inlet}	$= 14.734\left(\frac{101}{288.71}\right)\left(\frac{1.031*288.15}{7000}\right) * \left(\frac{51{,}255{,}602.23}{895.3^2}\right)$ = 13.99 m/s	$V = 14.734\left(\frac{P_b}{T_b}\right)\left(\frac{ZT}{P}\right)\left(\frac{Q_b}{D^2}\right)$

6.3 Case study: Pipeline cost calculations

Table 6.4. Pipeline cost calculations for a 36-inch pipeline, 1500 km long and operating at maximum capacity.

Steps	Calculation	Notes
Material costs	$= 1.1 * 63027 * EXP(36 * 0.0697) =$ $852{,}414.90\frac{2009\ US\$}{mile} = 837{,}789.24\ \frac{2019\ C\$}{km}$	1.1* 63027*exp(Diameter, in.*0.0697) * (Length, miles) CEPCI 2009 = 521.9; 2019 = 619.2

		Exchange rate: 0.75 US$/C$
Labor costs	$= 1.1 * [-51.393 * 36^2 + 43{,}523 * 36 + 16{,}171] = 1{,}668{,}033.04 \frac{2009\ US\$}{mile} = 1{,}639{,}413.06 \frac{2019\ C\$}{km}$	1.1 * ([-51.393 * (Diameter, in.)^2 + 43,523 * (Diameter, in.) + 16,171] * (Length, miles)) CEPCI 2009 = 521.9; 2019 = 619.2 Exchange rate: 0.75 US$/C$
Miscellaneous	$= 1.1 * [303.13 * 36^2 + 12{,}908 * 36 + 123{,}245] = 1{,}078{,}868.43 \frac{2009\ US\$}{mile} = 1{,}060{,}357.29 \frac{2019\ C\$}{km}$	1.1 * ([303.13 * (Diameter, in.)^2 + 12,908 * (Diameter, in.) + 123,245] * (Length, miles)) CEPCI 2009 = 521.9; 2019 = 619.2 Exchange rate: 0.75 US$/C$
Right of Way costs	$= [-9E - 13 * 36^2 + 4{,}417.1 * 36 + 164{,}241] = 323{,}256.60 \frac{2009\ US\$}{mile} = 317{,}710.19 \frac{2019\ C\$}{km}$	([-9E-13 * (Diameter, in.)^2 + 4,417.1 * (Diameter, in.) + 164,241] * (Length, miles)) CEPCI 2009 = 521.9; 2019 = 619.2 Exchange rate: 0.75 US$/C$
TIC_{pipe} (2019 C$)	$= 837{,}789.24 + 1{,}639{,}413.06 + 1{,}060{,}357.29 + 317{,}710.19$ $= 3{,}855{,}269.77 \frac{2019\ C\$}{km}$ $= 3{,}855{,}269.77 \frac{2019\ C\$}{km} * 1500\ km$ $= \mathbf{5,782,904,650.70\ C\$}$	$TIC_{pipe} = \text{Material cost} + \text{Labor cost} + \text{Miscellaneous cost} + \text{Right of way cost}$
TCI (2019 C$)	TCI = $5,782,904,650.70 + (0.4* $5,782,904,650.70) $= \mathbf{8,096,066,510.9\ C\$}$	TCI = TIC + Indirect Costs; where Indirect costs = 40% TIC
Annualized TCI (2019 C$/yr)	$CRF = \frac{0.08(1+0.08)^{50}}{(1+0.08)^{50}-1} = 0.0817$ Annualized TCI = $8,096,066,510.98 * 0.0817 $= \mathbf{661,795,616.47\ C\$/yr}$	$\text{Annualized TCI} \left[\frac{\$}{\text{year}}\right] = \text{TCI}(\$) *$ Capital recovery factor (CRF) $CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$ (i: Discount rate (%); n- Plant lifetime)

$\text{Capacity}_{\text{pipe}}$ $\left(\frac{\text{kgH}_2}{\text{day}}\right)$	$= 51{,}255{,}602.23\ \frac{Sm^3}{day} * 0.0834\ \frac{kgH_2}{Sm^3}$ $= \mathbf{4,278,788}\ \frac{\mathbf{kgH_2}}{\mathbf{day}}$	$\text{Capacity}_{\text{pipe}}\left(\frac{\text{kgH}_2}{\text{day}}\right)$ $= \text{Q}\left(\frac{\text{Sm}^3}{\text{day}}\right) * 0.0834$
$\text{Direct labor}_{\text{pipe}}$ (2019 C$/yr)	$= \left(8320 * \left(\frac{4{,}278{,}788}{100{,}000}\right)^{0.25}\right) * 49.66$ $= \mathbf{1,056,720.75\ C\$/yr}$	$\text{Direct labor}_{\text{pipe}}\left(\frac{\$}{\text{yr}}\right)$ $= \text{Annual hours}\left(\frac{\text{hrs}}{\text{yr}}\right) * \text{Labor rate}\left(\frac{\$}{\text{hr}}\right)$ Annual labor hours(hr/yr) $= 8320 * (x/100{,}000)\text{^}0.25$
Indirect labor $_{\text{pipe}}$ (2019 C$/yr)	$= \$\ 1{,}056{,}720.75/yr * 50\%$ $= \mathbf{528,360.38\ C\$/yr}$	Indirect labor cost ($/yr) = Direct labor($/yr) * Indirect labor factor (%) Indirect Labor factor = 50%
$\text{Fixed O\&M}_{pipe}$ (2019 C$/yr)	$= (0.026 * \$8{,}096{,}066{,}510.98)$ $= \mathbf{210,497,729.29\ C\$/yr}$	• O&M & repairs = 0.5% of TCI • Insurance = 1 % of TCI • Property tax = 1 % of TCI • License & permits = 0.1% of TCI
Non − energy $\text{OPEX}_{\text{pipe}}$ (2019 C$/yr)	$= \$1{,}079{,}820.42 + \$539{,}910.21 + \$210{,}497{,}729.29$ $= \mathbf{212,117,459.91\ C\$/yr}$	$\text{Non − energy opex}_{\text{pipe}}\left(\frac{\$}{\text{yr}}\right)$ $= \text{Total labor}\left(\frac{\$}{\text{yr}}\right) + \text{Fixed O\&M}\left(\frac{\$}{\text{yr}}\right)$
$\text{Capex}_{\text{pipe}}$ (2019 C$/kg H_2)	$= \frac{661{,}795{,}616.47\ \text{C\$/yr}}{(0.90 * 4{,}278{,}788 * 365)}$ $= \mathbf{0.47\ C\$/kg\ H2}$	$\text{Capex}_{\text{pipe}}\left[\frac{\$}{\text{kgH}_2}\right] = \frac{\left(\text{Annualized TCI}\left[\frac{\$}{\text{year}}\right]\right)}{\left(\text{Availability}[\%]\times\text{DesignCapacity}\left[\frac{\text{kgH}_2}{\text{day}}\right]\times 365\left[\frac{\text{days}}{\text{year}}\right]\right)}$
Non-energy $\text{OPEX}_{\text{pipe}}$ (2019 C$/kg H_2)	$= \frac{212{,}117{,}459.91\ \text{C\$/yr}}{(0.90 * 4{,}278{,}788 * 365)}$ $= \mathbf{0.15\ C\$/kg\ H2}$	$\text{Non − energy opex}_{\text{pipe}}\left[\frac{\$}{\text{kgH}_2}\right] = \frac{\left(\text{O\&M}\left[\frac{\$}{\text{year}}\right]\right)}{\left(\text{Availability}[\%]\times\text{DesignCapacity}\left[\frac{\text{kgH}_2}{\text{day}}\right]\times 365\left[\frac{\text{days}}{\text{year}}\right]\right)}$

$LCOH_{pipe}$ (2019 C$/kg H_2)	= 0.47 + 0.15 = **0.62 C$/kg H2**	$LCOH_{pipe}\left[\frac{\$}{kgH_2}\right] = \text{Non} - \text{energy opex}_{pipe}\left[\frac{\$}{kgH_2}\right] + \text{Capex}_{pipe}\left[\frac{\$}{kgH_2}\right]$

6.4 Case study: Compressor cost calculations

Table 6.5. Power and cost calculation of **inlet** compressor station for a 1500 km H_2 pipeline.

Steps	Calculation	Notes
N	$= \frac{[\log(70/20)]}{\log(2.1)} = 2$	$N = \frac{\log(\frac{P_{disc}}{P_{suc}})}{\log(x)}$; Round N up to the nearest whole number, i.e., 1.7 → 2.
T_{disc}	$= 293.15\left(1 + \frac{\left(\frac{70}{20}\right)^{\left(\frac{1.4-1}{2*1.4}\right)} - 1}{0.8}\right) = 365\ K$	$T_{disc} = T_{suc}\left[1 + \frac{\left(\frac{P_{disc}}{P_{suc}}\right)^{\left(\frac{k-1}{Nk}\right)} - 1}{\eta_{isen}}\right]$
$P_{avg}(Pa)$ and $T_{avg}(K)$	$P_{avg} = \frac{70 + 20}{2} = 45\ bar$ $T_{avg} = \frac{293.15 + 365}{2} = 329.1\ K$	$P_{avg} = \frac{P_{suc}+P_{disc}}{2}$ $T_{avg} = \frac{T_{suc}+T_{disc}}{2}$
Z	At calculated T_{avg} and P_{avg}; Z = 1.025	Using CoolProp excel plugin
q_M	$= \frac{\left(\frac{4,278,788}{0.002}\right)}{24 * 60 * 60}$ $= 24,761\ \frac{moles}{sec}$	Molar flow rate from $Capacity_{pipe}$ (See Table 6.4)
Actual Compressor power (kW)	$= 2\left(\frac{1.4}{1.4-1}\right)\left(\frac{1.025}{0.8}\right) 293.15\ (24,761)\ 8.314\left[\left(\frac{70}{20}\right)^{\left(\frac{1.4-1}{2*1.4}\right)} - 1\right]$ $= 106,076.99\ kW$	Power = $N\left(\frac{k}{k-1}\right)\left(\frac{Z}{\eta_{poly}}\right) T_{suc}\ (q_M) R\left[\left(\frac{P_{disc}}{P_{suc}}\right)^{\left(\frac{k-1}{Nk}\right)} - 1\right]$

Rated Compressor Power (kW)	$= \frac{106{,}076.99 \text{ kW}}{0.95}$ $= \mathbf{111,659.98 \quad kW}$	Rated Compressor Power (kW) $= \frac{\text{Actual Compressor Power (kW)}}{\text{Motor Efficiency (\%)}}$
Number of compressors	$= \frac{111{,}659.98}{16{,}000} = 6.98$	Maximum compressor size is taken as 16,000 kW.
UC (2019 C$)	= 6 * (3083.35 * 16,000^ 0.8335) + (3083.35 * $(16{,}000 * 0.98)$^ 0.8335) $= \mathbf{68,729,872.65\ C\$}$	UC = 3083.3 * [kW]^SF, where SF = 0.8335
TIC (2019 C$)	= $68,729,872.65 * 2 $= \mathbf{137,459,745.31\ C\$}$	TIC = UC * IF; where IF = 2.
TCI (2019 C$)	TCI = $ 137,459,745.31 + (0.4* $137,459,745.31) $= \mathbf{192,443,643.43\ C\$}$	TCI = TIC + Indirect Costs; where Indirect costs = 40% TIC
Annualized TCI (2019 C$/yr)	$\text{CRF} = \frac{0.08(1+0.08)^{15}}{(1+0.08)^{15}-1} = 0.1168$ Annualized TCI = $ 192,443,643.43 $*$ 0.1168 $= \$\ \mathbf{22,483,103.29\ /yr}$	Annualized TCI $\left[\frac{\$}{\text{year}}\right] = \text{TCI}(\$) *$ Capital recovery factor (CRF) $\text{CRF} = \frac{i\,(1+i)^n}{(1+i)^n - 1}$ (i – Discount rate (%); n- Compressor lifetime)
Energy Intensity (kWh/kg H_2)	$= (111{,}659.98 \quad \text{kW} * 24\frac{\text{hrs}}{\text{day}}) / \ (4{,}278{,}788\ \frac{kgH_2}{day})$ $= \mathbf{0.63 \frac{kWh}{kg\ H2}}$	
Electrical energy cost (2019 C$/yr)	$=111{,}659.98 \quad \text{kW} * 24\frac{\text{hrs}}{\text{day}} * \ 365\frac{\text{days}}{\text{year}} * \frac{0.11\$}{\text{kWh}}$ $= \mathbf{107,595,561.16\ C\$/yr}$	Electrical energy cost ($/yr) = Power (kW) $*$ Operating hours (hours/yr) $*$ Electricity price ($/kWh)
Direct labor cost (2019 C$ /yr)	= (288*(4,278,788 /100,000) ^0.25) *49.66 $= \mathbf{36,578.80\ C\$/yr}$	Direct labor cost ($/yr) = Annual hours(hours/yr) $*$ Labor cost ($/hour) Annual hours(hours/yr) = 288 $*$ (x/ 100000)^0.25

Indirect labor cost (2019 C$ /yr)	$= \$\,\mathbf{36,578.80} * 50\%$ $= \mathbf{18,289.40\ C\$/yr}$	Indirect labor cost $\left(\frac{\$}{yr}\right) =$ Direct labor $\left(\frac{\$}{yr}\right) *$ Indirect labor factor (%) Indirect Labor factor = 50%
Fixed O&M $\left(\frac{2019\ C\$}{yr}\right)$	$= (0.04 * \$137{,}459{,}745.31) + (0.021 * \$\,192{,}443{,}643.43)$ $= \mathbf{9,539,706.32\ C\$/yr}$	• O&M & repairs = 4% of TIC • Insurance = 1 % of TCI • Property tax = 1 % of TCI • License & permits = 0.1% of TCI
Non − Energy OPEX $\left(\frac{2019\ C\$}{yr}\right)$	$= \$\,36{,}578.80\ /yr + \$\,18{,}289.40\ /yr + \$\,9{,}539{,}706.32\ /yr$ $= \mathbf{9,594,574.52\ C\$/yr}$	Non − Energy OPEX $\left(\frac{\$}{yr}\right)$ = Total labor $\left(\frac{\$}{yr}\right)$ + Fixed O&M $\left(\frac{\$}{yr}\right)$
Capex (2019 C$/kg H_2)	$= \frac{22{,}483{,}103.29\ C\$/yr}{(0.90 * 4{,}278{,}788 * 365)}$ $= \mathbf{0.016\ C\$/kgH2}$	$Capex_{comp}\left[\frac{\$}{kgH_2}\right] = \frac{\left(\text{Annualized TCI}\left[\frac{\$}{year}\right]\right)}{\left(\text{Availability}[\%]\times \text{DesignCapacity}\left[\frac{kgH_2}{day}\right]\times 365\left[\frac{days}{year}\right]\right)}$
Non-energy OPEX (2019 C$ /kg H_2)	$= \frac{9{,}594{,}574.52\ C\$/yr}{(0.90 * 4{,}278{,}788 * 365)}$ $= \mathbf{0.007\ C\$/kgH2}$	$Opex_{comp}\left[\frac{\$}{kgH_2}\right] = \frac{\left(\text{O\&M}\left[\frac{\$}{year}\right]\right)}{\left(\text{Availability}[\%]\times \text{DesignCapacity}\left[\frac{kgH_2}{day}\right]\times 365\left[\frac{days}{year}\right]\right)}$
Energy (2019 C$/kg H_2)	$= \frac{107{,}595{,}561.16\ C\$/yr}{(0.90 * 4{,}278{,}788 * 365)}$ $= \mathbf{0.077\ C\$/kgH2}$	$Energy_{comp}\left[\frac{\$}{kgH_2}\right] = \frac{\left(\text{Energy}\left[\frac{\$}{year}\right]\right)}{\left(\text{Availability}[\%]\times \text{DesignCapacity}\left[\frac{kgH_2}{day}\right]\times 365\left[\frac{days}{year}\right]\right)}$
LCOH (2019 C$/kg H_2)	= 0.016 + 0.007 + 0.077 $= \mathbf{0.1\ C\$/kgH2}$	$LCOH_{comp}\left[\frac{\$}{kgH_2}\right] = Opex_{comp}\left[\frac{\$}{kgH_2}\right] + Capex_{comp}\left[\frac{\$}{kgH_2}\right]$

Table 6.6. Power and cost calculations of enroute compressor stations along a 1500 km H_2 pipeline.

Steps	Calculation	Notes
Number of enroute	= (1500/500)-1 =2	= (Total distance/Pipe length)-1

compressor stations		
N	$= \frac{[\log(70/28)]}{\log(2.1)} = 2$	$N = \frac{\log\left(\frac{P_{disc}}{P_{suc}}\right)}{\log(x)}$; Round N up to the nearest whole number, i.e., 1.7 → 2. P_{suc} is determined by pressure drop in pipeline. See Table 6.3.
T_{disc}	$= 293.15\left(1 + \frac{\left(\frac{70}{28}\right)^{\left(\frac{1.4-1}{2*1.4}\right)} - 1}{0.8}\right) = 344.5\ K$	$T_{disc} = T_{suc}\left[1 + \frac{\left(\frac{P_{disc}}{P_{suc}}\right)^{\left(\frac{k-1}{Nk}\right)} - 1}{\eta_{isen}}\right]$
$P_{avg}(Pa)$ and $T_{avg}(K)$	$P_{avg} = \frac{70 + 28}{2} = 49\ bar$ $T_{avg} = \frac{293.15 + 344.5}{2} = 318.8\ K$	$P_{avg} = \frac{P_{suc}+P_{disc}}{2}$ $T_{avg} = \frac{T_{suc}+T_{disc}}{2}$
Z	At calculated T_{avg} and P_{avg}; Z = 1.027	Using CoolProp excel plugin
q_M	$= \frac{\left(\frac{4{,}278{,}788}{0.002}\right)}{24*60*60} = 24{,}761\ \frac{moles}{sec}$	Molar flow rate from $Capacity_{pipe}$ (See Table 6.4)
Compressor power (kW) for single station	$= 2\left(\frac{1.4}{1.4-1}\right)\left(\frac{1.027}{0.8}\right)293.15\ (24{,}761)\ 8.314\left[\left(\frac{70}{28}\right)^{\left(\frac{1.4-1}{2*1.4}\right)} - 1\right]$ $= \mathbf{79{,}450.64\ kW}$	Power = $N\left(\frac{k}{k-1}\right)\left(\frac{Z}{\eta_{poly}}\right)T_{suc}\ (q_M)R\left[\left(\frac{P_{disc}}{P_{suc}}\right)^{\left(\frac{k-1}{Nk}\right)} - 1\right]$
Rated Compressor Power (kW) for single station	$= \frac{75{,}928.74\ \ kW}{0.95} = \mathbf{79{,}925.0\ \ kW}$	Rated Compressor Power (kW) $= \frac{\text{Actual Compressor Power (kW)}}{\text{Motor Efficiency (\%)}}$
Total rated Compressor Power (kW) of all enroute stations	$= 79{,}925\ * 2 = \mathbf{159{,}850\ \ kW}$	Number of enroute compressor stations = 2

Energy Intensity (kWh/kg H_2)	= (79,925 kW $*$ 24 $\frac{\text{hrs}}{\text{day}}$)/ (4,278,788 $\frac{kgH_2}{day}$) $= \mathbf{0.45} \frac{\mathbf{kWh}}{\mathbf{kg\ H2}}$	
Number of compressors at single enroute station	= $\frac{79{,}925}{16{,}000}$ = 4.99	Maximum compressor size is taken as 16,000 kW.
UC (2019 C$) for single enroute station	= 4 * (3083.35 * 16,000^ 0.8335) + (3083.35 * (16,000 $*$ 0.99)^ 0.8335) $= \mathbf{49,179,048.14\ C\$}$	UC = 3083.3 * [kW]^SF, where SF = 0.8335
TIC (2019 C$) for single enroute station	= $49,179,048.14* 2 $= \mathbf{98,358,096.28\ C\$}$	TIC = UC * IF; where IF = 2.
TIC (2019 C$) for all enroute stations	= $98,358,096.28 * 2 $= \mathbf{196,716,192.57\ C\$}$	Number of enroute compressor stations = 2
TCI (2019 C$) for all enroute stations	TCI = $196,716,192.57+ (0.4* $ $196,716,192.57) $= \mathbf{275,402,669.60\ C\$}$	TCI = TIC + Indirect Costs; where Indirect costs = 40% TIC
Annualized TCI (2019 C$/yr) for all enroute stations	$\text{CRF} = \frac{0.08(1+0.08)^{15}}{(1+0.08)^{15}-1} = 0.1168$ Annualized TCI = $275,402,669.60 $*$ 0.1168 $= \mathbf{32,175,168.56\ C\$/yr}$	$\text{Annualized TCI} \left[\frac{\$}{\text{year}}\right] = \text{TCI}(\$) *$ Capital recovery factor (CRF) $\text{CRF} = \frac{i\,(1+i)^n}{(1+i)^n-1}$ (i – Discount rate (%); n- Compressor lifetime)
Electrical energy cost (2019 C$/yr) for all enroute stations	=159,850 kW $* 24 \frac{\text{hrs}}{\text{day}} * 365 \frac{\text{days}}{\text{year}} * \frac{0.11\$}{\text{kWh}}$ $= \mathbf{154,031,439.50\ C\$/yr}$	Electrical energy cost ($/yr) = Power (kW) $*$ Operating hours (hours/yr) $*$ Electricity price ($/kWh)

Direct labor cost (2019 C$/yr) for all enroute stations	= 2* ((288*(4,278,788 /100,000) ^0.25) *49.66) $= \mathbf{73,157.59\ C\$/yr}$	Direct labor cost ($/yr) = Annual hours(hours/yr) * Labor cost ($/hour) Annual hours(hours/yr) = 288 * (x/100000)^0.25
Indirect labor cost (2019 C$ /yr) for all enroute stations	$= \$73{,}157.59 * 50\%$ $= \mathbf{36,578.80\ C\$/yr}$	$\text{Indirect labor cost}\left(\frac{\$}{yr}\right) =$ $\text{Direct labor}\left(\frac{\$}{yr}\right) *$ Indirect labor factor (%) Indirect Labor factor = 50%
Fixed O&M $\left(\frac{2019\ C\$}{yr}\right)$ for all enroute stations	$= (0.04 * \$196{,}716{,}192.57) + (0.021 * \$196{,}716{,}192.57)$ $= \mathbf{13,652,103.76\ C\$/yr}$	• O&M & repairs = 4% of TIC • Insurance = 1 % of TCI • Property tax = 1 % of TCI • License & permits = 0.1% of TCI
Non − Energy OPEX (2019 C$/yr) for all enroute stations	$= \$73{,}157.59/yr + \$36{,}578.80/yr + \$13{,}652{,}103.76/yr$ $= \mathbf{13,761,840.15\ C\$/yr}$	$\text{Non} - \text{Energy OPEX}\left(\frac{\$}{yr}\right)$ $= \text{Total labor}\left(\frac{\$}{yr}\right) + \text{Fixed O\&M}\left(\frac{\$}{yr}\right)$
Capex (2019 C$/kg H_2) for all enroute stations	$= \frac{32{,}175{,}168.56\ C\$/yr}{(0.90 * 4{,}278{,}788 * 365)}$ $= \mathbf{0.023\ C\$/kgH2}$	$\text{Capex}_{comp}\left[\frac{\$}{kgH_2}\right] = \frac{\left(\text{Annualized TCI}\left[\frac{\$}{year}\right]\right)}{\left(\text{Availability}[\%]\times\text{DesignCapacity}\left[\frac{kgH_2}{day}\right]\times 365\left[\frac{days}{year}\right]\right)}$
Non-energy OPEX (2019 C$/kg H_2) for all enroute stations	$= \frac{13{,}761{,}840.15\ C\$/yr}{(0.90 * 4{,}278{,}788 * 365)}$ $= \mathbf{0.01\ C\$/kgH2}$	$\text{Opex}_{comp}\left[\frac{\$}{kgH_2}\right] = \frac{\left(\text{O\&M}\left[\frac{\$}{year}\right]\right)}{\left(\text{Availability}[\%]\times\text{DesignCapacity}\left[\frac{kgH_2}{day}\right]\times 365\left[\frac{days}{year}\right]\right)}$
Energy (2019 C$/kg H_2) for all enroute stations	$= \frac{154{,}031{,}439.50\ C\$/yr}{(0.90 * 4{,}278{,}788 * 365)}$ $= \mathbf{0.11\ C\$/kgH2}$	$\text{Energy}_{comp}\left[\frac{\$}{kgH_2}\right] = \frac{\left(\text{Energy}\left[\frac{\$}{year}\right]\right)}{\left(\text{Availability}[\%]\times\text{DesignCapacity}\left[\frac{kgH_2}{day}\right]\times 365\left[\frac{days}{year}\right]\right)}$
LCOH (2019 C$/kg H_2) for	= 0.023+ 0.01 + 0.11 $= \mathbf{0.143\ C\$/kgH2}$	$\text{LCOH}_{comp}\left[\frac{\$}{kgH_2}\right] = \text{Opex}_{comp}\left[\frac{\$}{kgH_2}\right] + \text{Capex}_{comp}\left[\frac{\$}{kgH_2}\right]$

all enroute stations		

6.5 Case study: Total cost of pipeline system

1) Using **Tables 6.5 and 6.6**, we can calculate total cost of all (inlet and enroute) compressor stations

$$Capex_{comp} = 0.016 + 0.023 = 0.039\ \mathrm{C\$/kg_{H2}}$$

$$Non - Energy\ OPEX\ _{comp} = 0.007 + 0.01 = 0.017\ \mathrm{C\$/kg_{H2}}$$

$$Energy\ OPEX_{comp} = 0.077 + 0.11 = 0.19\ \mathrm{C\$/kg_{H2}}$$

$$\boldsymbol{LCOH_{comp} = 0.039 + 0.017 + 0.19 = 0.25\ \mathrm{C\$/kg_{H2}}}$$

2) Using the calculated values from **Tables 6.6, 6.5 and 6.6** and equations 10-13, we can calculate the total cost of pipeline system.

$$Capex_{pipe-system} = 0.47 + 0.039 = 0.51\ \mathrm{C\$/kg_{H2}}$$

$$Non - Energy\ OPEX_{pipe-system} = 0.15 + 0.017 = 0.17\ \mathrm{C\$/kg_{H2}}$$

$$Energy\ OPEX_{pipe-system} = 0.19\ \mathrm{C\$/kg_{H2}}$$

$$\boldsymbol{LCOH_{pipe-system} = 0.51 + 0.17 + 0.19 = 0.87\ \mathrm{C\$/kg_{H2}}}$$

7 RESULTS AND DISCUSSION

7.1 A 1500 km pipeline system

In section 6, we presented a detailed cost calculation of a 36-inch H_2 pipeline with a total distance of 1500 km and compressor stations every 500 km. The optimization of distance between compressor stations involves an analysis of the complex trade-offs between required pipeline capacity, capital, and operating expenditure for different pipeline sizes. In this section we present some results and discussions for different pipe sizes and with compressor stations placed every 500, 300 or 100 km. All other parameters used for the analysis are the same as case study presented in section 6 and summarized in **Tables 6.1 and 6.2**.

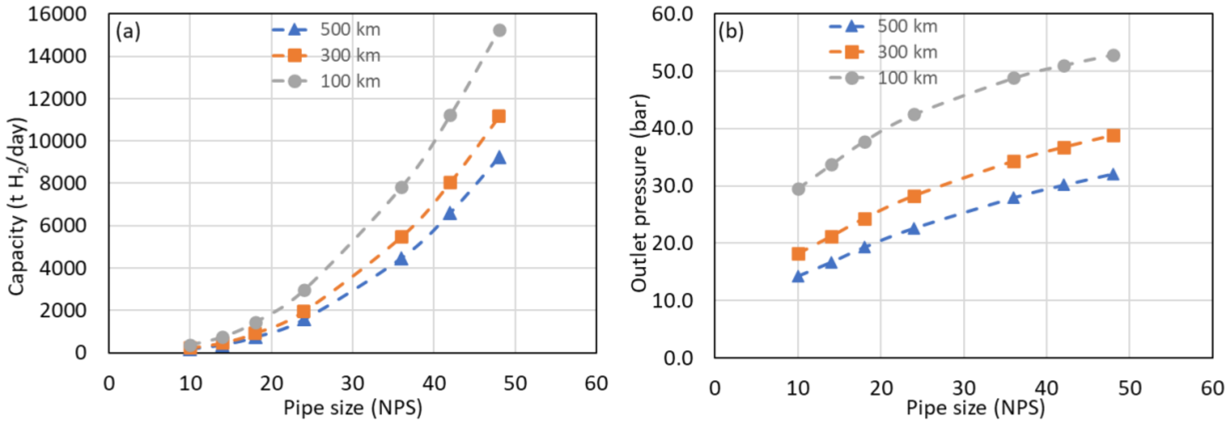

Figure 7.1. (a) Pipeline H_2 capacity (t_{H2}/day) and (b) Outlet pressure (bar) versus pipe size (NPS) as function of distance between compressor stations.

Note: The inlet pressure was assumed to be 70 bar, outlet gas velocity of 35 m/s and the total distance is 1500 km. Other assumptions as in **Tables 6.1 and 6.2**.

Figure 7.1(a) shows the maximum H_2 transportation capacity of pipeline as function of nominal pipe size (NPS). The pipeline capacity is calculated from the flow rates for different pipe lengths (500, 300 and 100 km) following the methodology described in **Table 6.3**. As expected, the capacity increases with larger pipe size increasing from ~183 t_{H2}/day for a 10-inch pipeline to ~ 9235 t_{H2}/day for 48-inch pipeline with compressor stations placed every 500 km. With an increase in number of compressor stations that are placed every 100 km, the pipeline capacity can be increased significantly, reaching up to a maximum of ~15,233 t_{H2}/day for a 48-inch pipeline. This primarily is due to lower pressure drop in the pipeline over a shorter pipe length of 100 km versus 500 km as shown in **Figure 7.1(b)**. In a 48-inch pipeline the outlet pressure is ~32 bar when the pipe length or in other words distance between compressor stations is ~500 km. When we decrease the distance the pipe length to 100 km, the outlet pressure increases to ~52.9 bar.

This increase in capacity and outlet pressure comes at a cost, that is associated with the capital and operating cost of the extra compressor stations as discussed next.

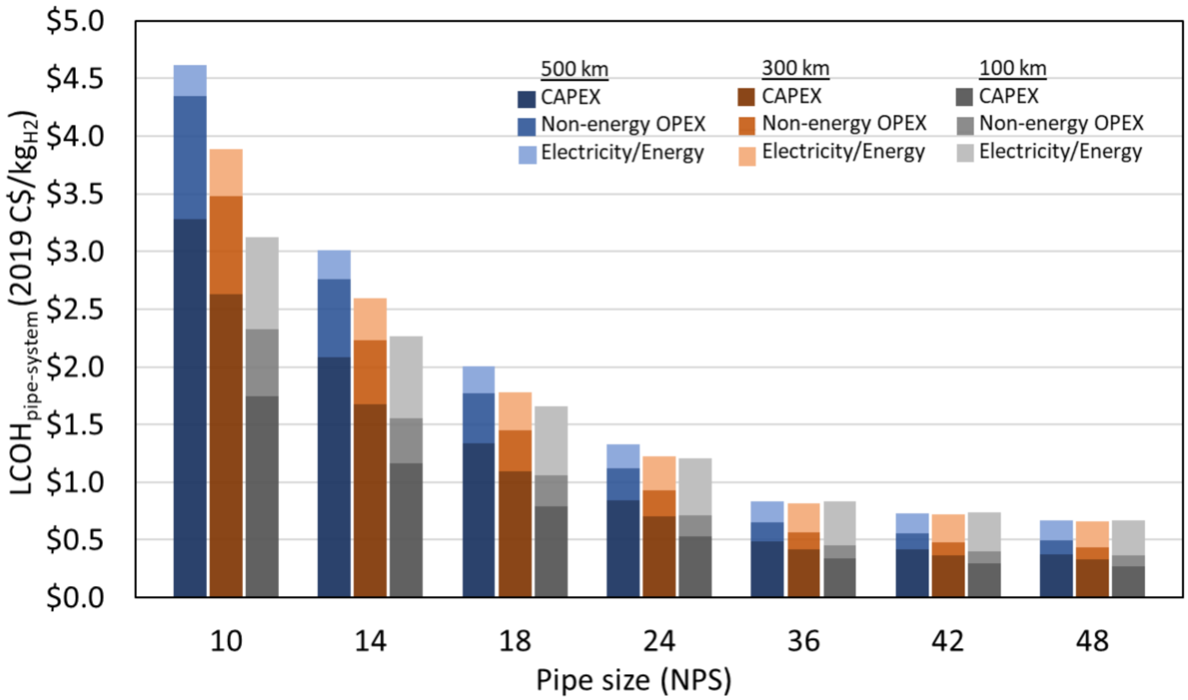

Figure 7.2. LCOH$_{pipe\text{-}system}$ divided into: Capex$_{pipe\text{-}system}$, Non-Energy OPEX$_{pipe\text{-}system}$ and Electricity /Energy$_{pipe\text{-}system}$ versus pipe size (NPS).

Note: The cost analysis is performed for different pipe lengths (distance between compressor stations): 500 km, 300 km, 100 km. The inlet pressure was assumed to be 70 bar, outlet gas velocity of 35 m/s and the total distance is 1500 km. Other assumptions as in **Tables 6.1 and 6.2**.

The analysis of the levelized cost of the pipeline system ($LCOH_{pipe-system}$) as shown in **Figure 7.2** reveals two key features. Firstly, that for a total distance of 1500 km, pipeline transportation of H_2 will only make economic sense with large (>24 NPS) pipelines that are capable for delivering thousands of t_{H2}/day (Figure 7.1(a)). Secondly, decreasing the pipe length or in other words adding additional compressor stations to increase pipeline capacity can be beneficial for smaller pipes (<24 NPS) decreasing the levelized cost of H_2 transported through the pipeline. In other words, the extra capital and operating cost of compression is worth the investment to increase the overall capacity for smaller pipes and in return lower the cost of H_2 transported. With the use of larger pipes, the additional compressor stations do not add any benefit in terms of reducing the levelized cost of H_2. A detailed breakdown of this trend can be studied by analyzing the CAPEX, Non-energy OPEX, and electricity/energy costs. As expected, we observe that the additional compressor stations (extra capacity) increase the associated energy/electricity costs (100 km > 300 km > 500 km). The additional capacity added to smaller pipes leads to significant reduction in capex and non-energy OPEX costs which makes up for the extra electricity costs which is not the case for larger pipes (>24 NPS).

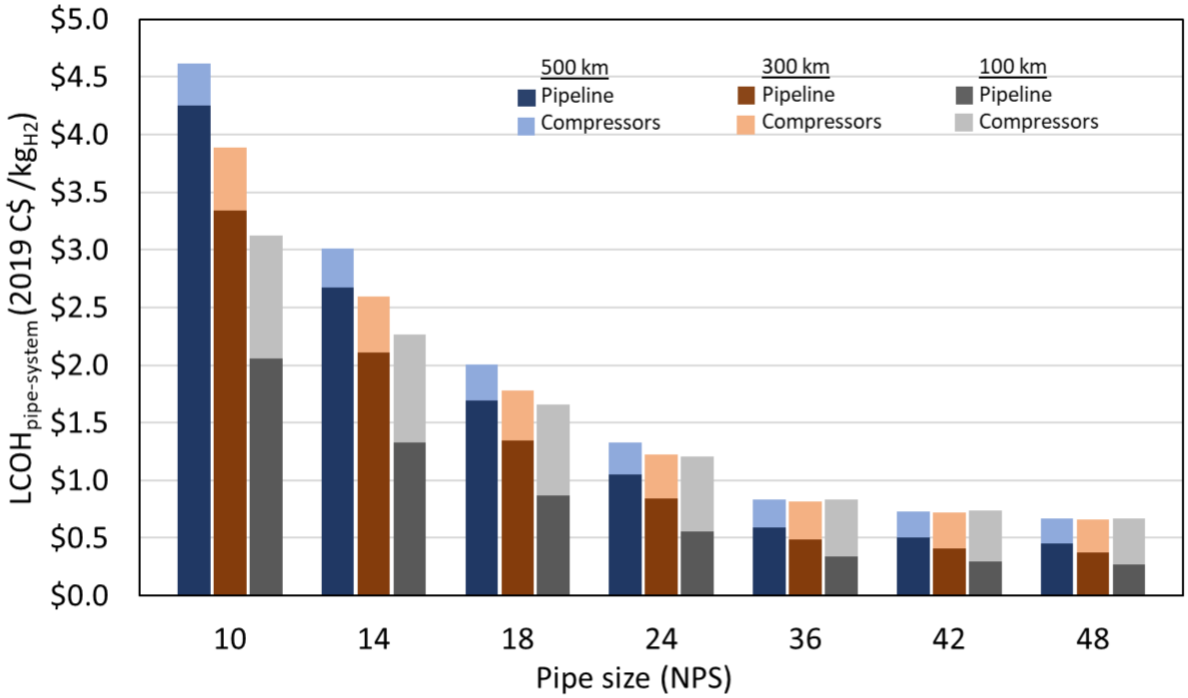

Figure 7.3. $LCOH_{pipe-system}$ divided into: $LCOH_{pipe}$ and $LCOH_{comp}$ versus pipe size (NPS).

Note: The cost analysis is performed for different pipe lengths (distance between compressor stations): 500 km, 300 km, 100 km. The inlet pressure was assumed to be 70 bar, outlet gas velocity of 35 m/s and the total distance is 1500 km. Other assumptions as in **Tables 6.1 and 6.2**.

The levelized cost of **Figure 7.2** can also be broken down into pipeline costs ($LCOH_{pipe}$) and compressor costs ($LCOH_{comp}$) as shown in **Figure 7.3**. For a given pipe size, we observe that $LCOH_{pipe}$ decreases with increasing the number of compressor stations due to the increased capacity of the pipeline with identical pipeline capital investment. As an example, for a NPS 10 pipe, the $LCOH_{pipe}$ decreased from 4.25 C$/kg$_{H2}$ to 2.05 C$/kg$_{H2}$ when compressors stations are placed every 500 km versus 100 km, respectively. This is due to capacity increase in pipeline capacity from ~183 t$_{H2}$/day to ~380 t$_{H2}$/day. The increase in capacity comes at a cost of increased $LCOH_{comp}$ from 0.36 C$/kg$_{H2}$ to 1.07 C$/kg$_{H2}$. The second observation is that using large pipelines with minimum number of compressor stations is the best way to transport H_2 across large distances. Nonetheless, the case study presented in **Section 6** and results of **Section 7.1**, indicate that pipeline design and costing is a complex analysis with many variables.

7.1 Required demand for low-cost pipeline delivery

In Section 7.1, we analyzed the effect of pipe size and distance between compressor stations on the $LCOH_{pipe-system}$, for a total distance of 1500 km. In this section we present the results of an analysis to understand the capacities or in other words demand in t_{H2}/day needed to make low-cost pipeline delivery possible for total distance of 10, 30, 100 and 300 km. This was done assuming only an inlet compressor station which compresses H_2 from 20 to 70 bars, which is the inlet pressure of pipeline. All other parameters used for the analysis are the same as summarized in **Tables 6.1 and 6.2**.

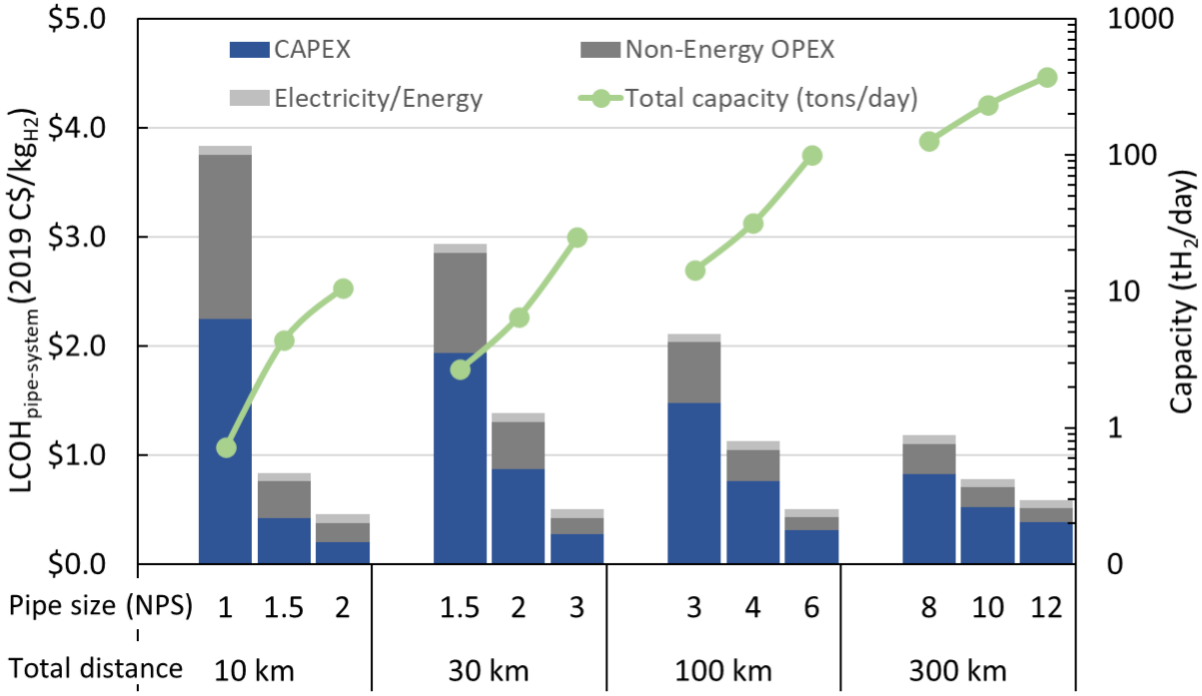

Figure 7.4. $LCOH_{pipe\text{-}system}$ divided into: $Capex_{pipe\text{-}system}$, Non-Energy $OPEX_{pipe\text{-}system}$ and Electricity /$Energy_{pipe\text{-}system\ for}$ different total distance of 10, 30, 100 and 300 km.

Note: For each distance, different pipe sizes were modelled to calculated capacity and $LCOH_{pipe-system}$. The inlet pressure for pipeline was assumed to be 70 bar with an outlet gas velocity of 35 m/s.

Figure 7.4 shows the $LCOH_{pipe-system}$ and pipeline capacity (t_{H2}/day) as function of different pipe sizes and distance. The results indicate that to achieve a low pipeline delivery cost of ~ 0.5-0.6 C\$/kg_{H2}, there is a minimum demand or pipeline capacity/size required as a function of total distance. This required demand or pipeline capacity increases as function total distance from ~10.5 t_{H2}/day for 10 km, to ~ 370 t_{H2}/day for 300 km pipeline. The results lead us to propose a rule of thumb: "We roughly require a demand ~1-1.2 t_{H2}/day per km of pipeline to drive economic viability". This can be considered for short distance pipelines without the need of compressor stations along length of pipeline.

8 SUMMARY AND OUTLOOK

Low carbon H_2 is projected to play a key role as an energy carrier and become the fuel of choice in hard to decarbonize sectors such as heavy transport, heating, and steel production. At present, almost all the H_2 consumed in the world is close to the production site. The development of a H_2 economy will rely on a well-developed infrastructure that can distribute H_2 safely and efficiently to consumers. Our techno-economic results indicate that transporting H_2 via pipelines is a low-cost distribution option (< 1 C$/$kg_{H2}$) when operating at a large scale i.e., 100s of t_{H2}/day to 1000s t_{H2}/day depending on distance. However, construction and installation of new pipelines will need significant private capital investment, which in turn will demand sufficient financial return. Therefore, for an initial transition period where H_2 demand is not enough to secure financing for large pipelines, federal support might be needed to speed up the transition.

The transition to a H_2 economy will also significantly depend on how effectively and quickly we can adapt our current natural gas pipeline infrastructure for H_2 transmission. A recent study on German pipeline network suggested that we could cut down H_2 transport cost by 20% to 60% by repurposing natural gas pipelines versus newly constructed pipelines [42]. This would involve various modifications to the compressors, valves, meters, welds, and leak detection systems. Such repurposing has been demonstrated in a few places. One such example was in the United States, where Air Liquide purchased two crude oil pipelines in Texas, and successfully repurposed them for H_2 transport [4]. Other promising solutions include using fiber reinforced polymer (FRP) pipelines for H_2 distribution. The installation costs for FRP pipelines have been demonstrated to be about 20% less than that of steel pipelines [43]. Furthermore, there is a need to develop low cost, reliable, and durable centrifugal H_2 compressors for use in pipelines. Lastly but most importantly, the transition to a H_2 economy will also need productive discussions among key stakeholders and enforcement of policies such as carbon pricing.

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