Hydrogen and the Decarbonization of Steel Production in Canada

REACHING ECONOMIES OF SCALE

CSPA ACPA
Canadian Steel Producers Association

The Transition Accelerator

L'Accélérateur de transition

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TABLE OF CONTENTS

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.

FIGURES, TABLES, BOXES

List of Figures

List of Tables

List of Boxes

LIST OF ABBREVIATIONS

ABBREVIATION	DEFINITION
ATR	Auto-thermal reforming
BEV	Battery-electric vehicle
BF-BOF	Blast Furnace – Basic Oxygen Furnace
BFG	Blast Furnace Gas
BoP	Balance of plant
BOS	Basic Oxygen Steelmaking
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CCUS	Carbon capture, and utilization/storage
COG	Coke Oven Gas
COP	Coefficient of performance (for heat pumps)
DRI	Direct Reduced Iron
EAF	Electric Arc Furnace
GHG	Greenhouse Gas
HDV	Heavy-duty vehicle
HFCEV	Hydrogen fuel cell electric vehicle
HHV	Higher heating value
HM	Hot Metal
ICEV	Internal combustion engine vehicle
LCOH	Levelized cost of hydrogen
LDV	Light-duty vehicle

LH2	Liquid hydrogen
LHV	Lower heating value
MDEA	Methyl diethanolamine
MDV	Medium-duty vehicle
MMSCFD	Million standard cubic feet per day
MSW	Municipal solid waste
NG	Natural Gas
NPS	Nominal pipe size
O&M	Operating and maintenance (costs)
OPEX	Operating expenditure
PCI	Pulverized Coal Injection
PEM	Proton Exchange Membrane
PSA	Pressure-Swing Adsorption
RF	Reheat Furnace
SMR	Steam Methane Reforming
TBD	To be determined
TCI	Total capital investment
THM	(Imperial long) Ton of Hot Metal
ton	Imperial long ton (2,240 lb) or short ton (2,000 lb), as indicated in the text
tonne	Metric tonne (1,000 kg)
VKT	Vehicle kilometres travelled
WGSR	Water gas shift reactor

ACKNOWLEDGMENTS

EXECUTIVE SUMMARY

This report explores the potential for hydrogen in the decarbonization of steel production in Canada. Canada's steel sector currently produces about 15 Mt CO_2e/year (2% of Canada's GHG emissions), with the majority from Ontario where coal, coke and natural gas are utilized in large blast furnaces – basic oxygen furnaces (BF-BOF) to convert iron ore into the iron required for steelmaking. Hydrogen, produced with low-greenhouse gas (GHG) emissions, has the potential to play a significant role in the industry's decarbonization efforts, given its potential application as a fuel and reduction agent in the BF-BOF process or to reheat steel.

The focus of this report are the economic, technical and logistical challenges that need to be overcome to support hydrogen use in steelmaking. The report also applies these insights to a detailed case study on the use of hydrogen in the direct reduced iron (DRI) process used with iron ore as a feedstock.

Globally, hydrogen is being explored as a key strategy to achieve net zero in steel making, since many of the other decarbonization paths only provide incremental reductions. This study maps out key aspects that must be considered to see a hydrogen potential realized for Canadian steelmaking, such as logistics, costs, increased electricity use, and hydrogen demand from other sectors.

Chapter 1 outlines the Canadian steel industry's aspirational goal to achieve net-zero greenhouse gas (GHG) emissions by 2050 and highlights the range of potential decarbonization pathways. Options beyond hydrogen adoption are not discussed in any depth in this report but should be considered as integral in the steel sector's decarbonization strategy.

Chapter 2 describes the energy and material flows in various steelmaking processes. Shifting from primary ironmaking to steel recycling through the use of electric arc furnaces (EAF) would significantly reduce emissions per tonne of steel produced, but there is still a demand for virgin steel production by the BF-BOF or DRI-EAF processes but without the GHG emissions. Further, there is insufficient scrap steel globally to fulfill demand via EAF technology alone.

When fueled by natural gas (NG), the DRI-EAF process can reduce Scope 1 (on-site) GHGs emissions associated with the primary production of a tonne of steel by two-thirds compared with the existing BF-BOF technology, albeit linked to significantly increased electricity use and hence, higher upstream (Scope 2) emissions, leading to a lifecycle GHG benefit of about 40% or 50% per tonne of steel compared to the integrated route.

Further emission reductions can be achieved if the DRI-EAF process is fueled by hydrogen (H_2 DRI-EAF) instead of natural gas, producing only water when the hydrogen is oxidized. While it is theoretically possible to achieve zero-emission steel production from iron ore using the H_2 DRI-EAF process, the high cost of low-

GHG hydrogen production and delivery to a steel plant is challenging for the industry today and for the foreseeable future.

Chapter 3 examines Canadian and international efforts to incorporate hydrogen into the steelmaking process. This review shows that in addition to its use in the H_2 DRI-EAF process, zero-emission hydrogen can also be used as a secondary fuel in a blast furnace or to reheat steel. Although low-GHG hydrogen is being adopted to various degrees by companies around the world, availability and cost are issues that have limited the use of hydrogen to date.

Chapter 4 provides details on the production, transport, storage, and use of hydrogen as an energy carrier, including the logistical and economic challenges. For low-GHG hydrogen use as a heating fuel or reductant (as in steelmaking), a target price of less than C\$3/kg H_2 is proposed, equivalent to three to four times what the industry currently pays for natural gas. If hydrogen is to be made from water electrolysis using low-GHG electricity ('Green' H_2), the required delivered electricity cost is about C\$40/MWh for at least 6,000 hours per year. That would be a challenge.

> "For low-GHG hydrogen to be used as a heating fuel or reductant in steel making, a target price of less than C\$3/kg H_2 is proposed, equivalent to three to four times what the industry currently pays for natural gas."

However, if low-GHG hydrogen is made by reforming natural gas where the by-product CO_2 is captured and sequestered (CCS) in the sub-surface ('blue' H_2), the cost of production would be about C\$2.25/kg H_2 at a natural gas price of C\$5.5/GJ_{hhv}. However, the appropriate geology for CO_2 sequestration (about 9 t CO_2/t H_2) would need to be co-located with steel production, or the hydrogen would need to be transported to the steel plant.

Chapter 5 applies these insights to a case study for steel production in the Hamilton region and concludes that at the economy of scale needed for the ArcelorMittal Dofasco plant (492 t H_2/d), blue hydrogen can be made at a delivered cost of about C\$3/kg H_2, assuming either hydrogen production and CO_2 sequestration near Lake Erie (a limited resource) with a pipeline to Hamilton or hydrogen production and CCS in nearby US states plus a dedicated 400 km hydrogen pipeline to Hamilton.

The steel industry is not the only sector where low-GHG hydrogen is seen as a potential climate change solution. **Chapter 6** deconstructs the energy system of Ontario in 2019 to assess the most credible net-zero technology solutions for each sector, including direct electrification, biofuels, hydrogen and fossil fuels coupled to CCS. In addition to doubling the electrical grid and maximizing the province's biofuel potential, by 2050, Southwestern Ontario was projected to require 9,000 t H_2/day for heavy transport, agriculture, and heat for buildings and other industries. That is 18 times larger than the estimated demand for hydrogen for steelmaking in the ArcelorMittal Dofasco plant in Hamilton.

By increasing the size and flow through a 400 km hydrogen pipeline serving multiple demand sectors in Ontario, blue hydrogen could be delivered to the Hamilton region for about C$2.50/kg H_2 from nearby US states that have both NG production (assumed C$4/GJ NG) and CCS potential. Although this would be an excellent price for fuel hydrogen in Ontario, its use in the H2 DRI-EAF process represents a high cost (C$201-364/t CO_2 abated) for mitigating GHG emissions compared to NG DRI-EAF.

> **"By increasing the size and flow through a 400 km hydrogen pipeline, blue hydrogen could be delivered to the Hamilton region for about C$2.5/kg H_2 from nearby US states that have both NG production (assumed 4C$/GJ NG) and CCS potential."**

To minimize costs and maximize benefits to the steel industry and Canada, we recommend the following:

- ☐ **Reinvest revenue created from carbon pricing in the steelmaking sector** into steel decarbonization technologies that are on a transition pathway to net zero. Through the use of border carbon adjustments, companies that produce and use low-GHG steel can be rewarded, while the higher emitters pay a higher cost.

- ☐ **Understand the impact of other US and Canadian policies on the cost of low-GHG hydrogen production.** These include the 45Q Tax Credit and Inflation Reduction Act in the USA, the CCS tax credit and clean hydrogen investment tax credit in Canada, and other policy tools, such as contracts for difference and the clean fuel standard.

- ☐ **Monitor the progress of innovations in low-GHG hydrogen production** - particularly natural gas pyrolysis to hydrogen and carbon black and biomass (or municipal solid waste) to hydrogen technologies.

- ☐ **Work with the region and province to develop and deploy a regional strategy around hydrogen,** building on the fact that the economics of hydrogen production, storage and transport are significantly improved with scale, and the steel industry can be an anchor tenant for a much larger hydrogen economy.

- ☐ **Build a premium market for low-GHG steel** through government procurement and targeting low-GHG steel use in vehicle manufacture and other demand sectors. A standard for low-GHG steel needs to be defined, and a branding and communications program built around this premium product.

1 INTRODUCTION

The iron and steel industry generates about 6% of the world's carbon dioxide (CO_2) emissions from the use of fossil fuels. In 2019, the Canadian steel industry accounted for approximately 15 million tonnes of CO_2 emissions — 2% of Canada's national inventory and close to 20% of the nation's emissions from heavy industry [1]. Compared to other countries, Canada's steel industry has some of the lowest greenhouse gas (GHG) emissions and has already reduced its emissions by 32% from 1990 to 2016 [2]. Canada's commitment to reduce GHG emissions by 40% of 2005 levels by 2030 and then to reach net-zero GHG emissions by 2050 requires additional efforts to fully decarbonize steel production over time. In 2020, the Canadian Steel Producers Association (CSPA) released its aspirational Climate Call to Action, aligning itself with the national net-zero goal by 2050 [3]. ArcelorMittal Dofasco committed to an intermediate target of a 25% reduction of its worldwide CO_2 emissions by 2030, Algoma Steel intends to move away from coke use towards a mini mill concept based on recycled scrap, and other companies are likewise investing in transformational technologies to lower their carbon footprint.

China currently produces more than half of the world's steel, and the world currently has more capacity than demand. As such, industry margins are small and national policies need to consider both environmental goals and the competitiveness of their industries. Whereas border tariffs can address such issues, developing markets for "green" steel with a lower carbon footprint will help the industry decarbonize and drive the required investments. The cost of low-GHG steel may be considerably higher than "grey" steel, at a cost premium between 10 and 25%, yet for its users, steel is only one out of many components, and such price increases have relatively small impacts on the cost of final products, such as cars. As carmakers declare their own net-zero goals [4] and other industries, such as beverages, computers, and others [5] have declared their intention to buy low-GHG steel, markets are bound to develop and can be harnessed by the first movers in this field.

Table 1.1. provides a high-level overview of prevalent decarbonization options for the steel industry, including hydrogen, carbon capture, clean electricity grids and other breakthrough technologies. Each has its own advantages, disadvantages, and relative potentials. The most likely path forward will be a combination of several solutions, some of which can be adopted today and some later. These new solutions cannot all be realized by the steel industry alone and face barriers such as reliable supply, technical constraints, affordability, and regional limitations.

Hydrogen appears to be a key strategy to achieve net zero since many of the other options can only provide incremental reductions. Moving from a Blast Furnace-Basic Oxygen Furnace (BF-BOF) to a Direct Reduction of Iron-Electric arc Furnace (DRI-EAF), as is already envisaged by ArcelorMittal in Hamilton, would almost triple electricity demand per tonne of steel produced [6]. For Ontario to replace the existing production capacity of about ten million tonnes of steel per year from BF-BOF, a new power generation capacity of

685 MW (net) would be needed. The new Molten Oxide Electrolysis process would require even higher amounts of power, at about 4 MWh per tonne of steel (4.5 GW for Ontario). biochar use, the steel industry's total demand in Ontario could be equal to the current availability of wood residue (about 2 million dry tonnes per year).

This report looks specifically at hydrogen as one potential option for the Canadian steel industry to reduce and eventually eliminate the GHG emissions associated with fossil fuel use. Chapter 2 describes the basic processes of steelmaking and related energy use, and Chapter 3 provides an international scan of ongoing decarbonization efforts using hydrogen in the steel industry. Chapter 4 discusses hydrogen generation options and related costs, so Chapter 5 can focus on a case study for steel production with hydrogen in the Hamilton region. Chapter 6 provides Ontario context on potential hydrogen users, and resulting costs of blue hydrogen at economies-of-scale in Ontario, and Chapter 7 then draws conclusions with respect to a way forward for the industry and government to enable a transition towards hydrogen.

Options beyond hydrogen adoption are not discussed in any depth in this report but should be considered as integral in the steel sector's decarbonization strategy. CSPA has other publications [2] which identify technologies beyond those in **Table 1.1.** It is noted that upstream and downstream emissions related to steel production were not considered within the context of this report. Furthermore, there are sectors beyond steel that are relevant for hydrogen adoption and necessary to reach economies of scale (see Chapter 6).

Table 1.1. Decarbonization Options for the Steel Industry

Option	Potential	Limitations and Opportunities
Carbon capture and storage at steel plants	Can achieve a 50-65% reduction	• Requires suitable geological formations, which are not always available near steel industry locations • Environmental impacts (water use, air emissions)
DRI with natural gas	60% reduction	• Requires retrofits for infrastructure designed for coke and coal • Operates with EAF but in batch mode • Can be retrofitted to 100% hydrogen • Can be joined with CCS to further decrease GHG emissions
Renewable natural gas	Can theoretically displace natural gas	• Limited availability of RNG • Limited current use of natural gas by the Canadian industry • High cost
Molten Oxide Electrolysis	Up to 100% decarbonization, depending on electricity source	• Very limited capacities in Canada to accommodate new large-scale power users • Requires very large amounts of low-GHG electricity • Process is pre-commercial • Requires replacing existing infrastructure
HIsarna process	About 20% decarbonization	• More energy efficient than BF-BOF but still uses coal • Pre-commercial technology
Biomass	Up to about 60% decarbonization of steel carbon intensity [6]	• Supply chains not developed; limited supply • Can be used to fully replace coal in DRI process • Technology still pre-commercial • Adding CCS could further reduce emissions
Co-firing hydrogen in existing blast furnaces	Up to 21% fossil fuel displacement in blast furnace [6]	• Cannot fully decarbonize with existing infrastructure • Hydrogen cost bound to be very high for limited demand
DRI with hydrogen	Close to 100% decarbonization, depending on hydrogen source	• No existing supply infrastructure • Steel industry demand insufficient for investing in pipelines • Blue hydrogen requires suitable geological formations for sequestration • Green hydrogen requires substantial new power generation capacities • Infrastructure retrofits or renewals required • High cost

2 STEELMAKING BASICS

2.1 Steel Production in Canada

2.1.1 Production

Iron and steel production in Canada has a long history, with the first ironworks being established in Upper Canada's Port Dover in 1816 before the Confederation of Canada [7]. In 1874, Canada opened its first steelmaking facility in Londonderry, Nova Scotia, operating an open-hearth furnace with coke ovens installed in 1876 [7]. In terms of production, Canada is often within the top 20 steel-producing countries in the world, with almost 13 million tonnes of crude steel production in 2021 [8].
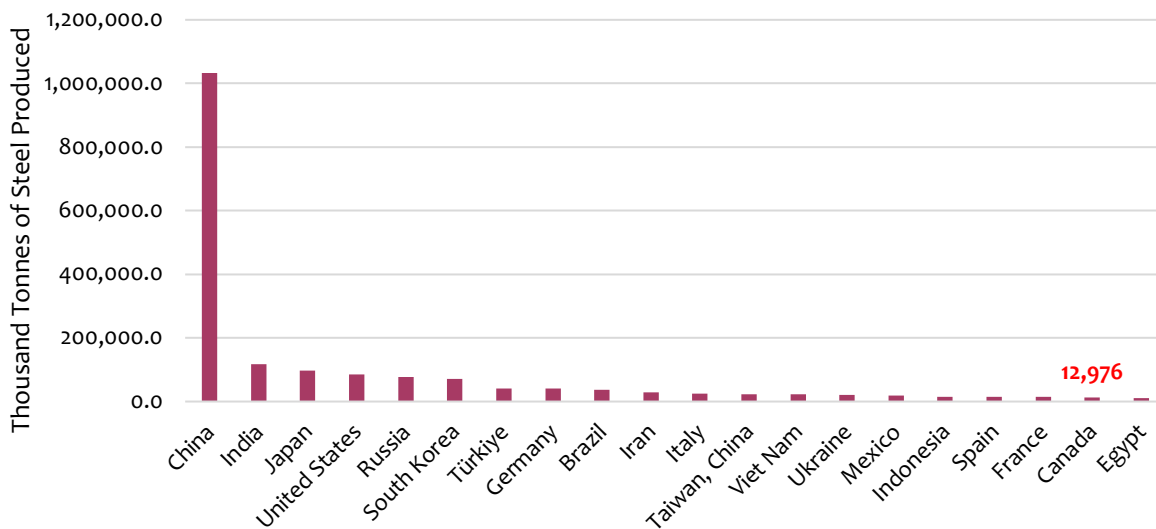
Figure 2.1. Top 20 steel producers in 2021 [8].

China dominates the global market for steel production, producing more steel (53% of global steel in 2021) than the rest of the world combined [8]. For the past five years, Canada has seen relatively consistent steel production with a drop in production in 2020, which can most likely be attributed to the COVID-19 pandemic [8].
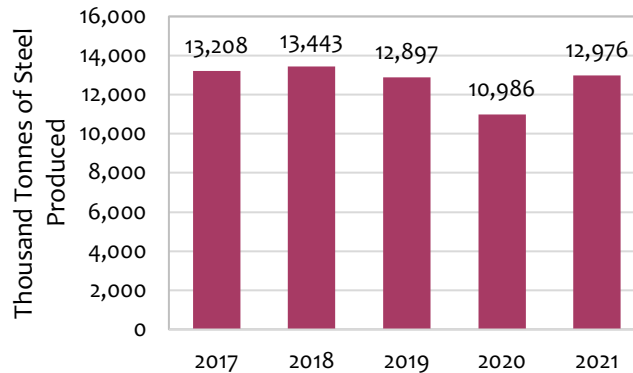
Figure 2.2. Canada steel production, 2017 to 2021 [8]

Canada produces steel using two methods: the integrated route and the mini mill route. The integrated route utilizes a blast furnace (BF) and a basic oxygen furnace (BOF) to produce steel primarily from raw materials like iron ore and coal, typically 25% scrap. The mini mill route utilizes electric arc furnaces (EAF) to produce steel from steel scrap, direct reduced iron (DRI) and sometimes, iron ore. In addition, Canada has numerous finishing plants which take semifinished steel products (billets, slabs etc.) and form them into finished products (plates, strips etc.). The EAF route, usually based on a recycling process, is more energy and emission efficient than the BOF route and therefore has received a lot of attention in the last few decades. Yet, overall steel demand cannot be filled with EAF mills using mainly recycled steel scrap, nor can these mills achieve the quality parameters required, thus making integrated mills an important part of the industry. Through the use of DRI in an EAF, manufacturing higher-quality steel is possible [9], yet integrated mills may still be needed to produce steels with the most stringent residual quality requirements.

About 46% of steel made in Canada comes from the EAF route, the rest from integrated mills [8]. The Canadian & Ontario governments recently invested almost C$1.3 billion for BOF to EAF conversions at Algoma Steel and ArcelorMittal Hamilton, which will drastically increase the share of EAF steel production in the future [10,11].

A map showing the location and type of Canadian steelmaking plants is shown below, as well as a table detailing the steel companies in Canada (**Table 2.1**). Stelco's Hamilton operation includes a galvanizing line as well as a cokemaking facility and batch annealing facility. In addition, the ArcelorMittal Long Products mini mill in Quebec also operates a DRI facility (the only one of its kind in Canada). Rio Tinto operates a unique facility with ilmenite (Iron(II) titanate) as the feedstock, while ArcelorMittal Dofasco in Hamilton operates both a BOF and an EAF.
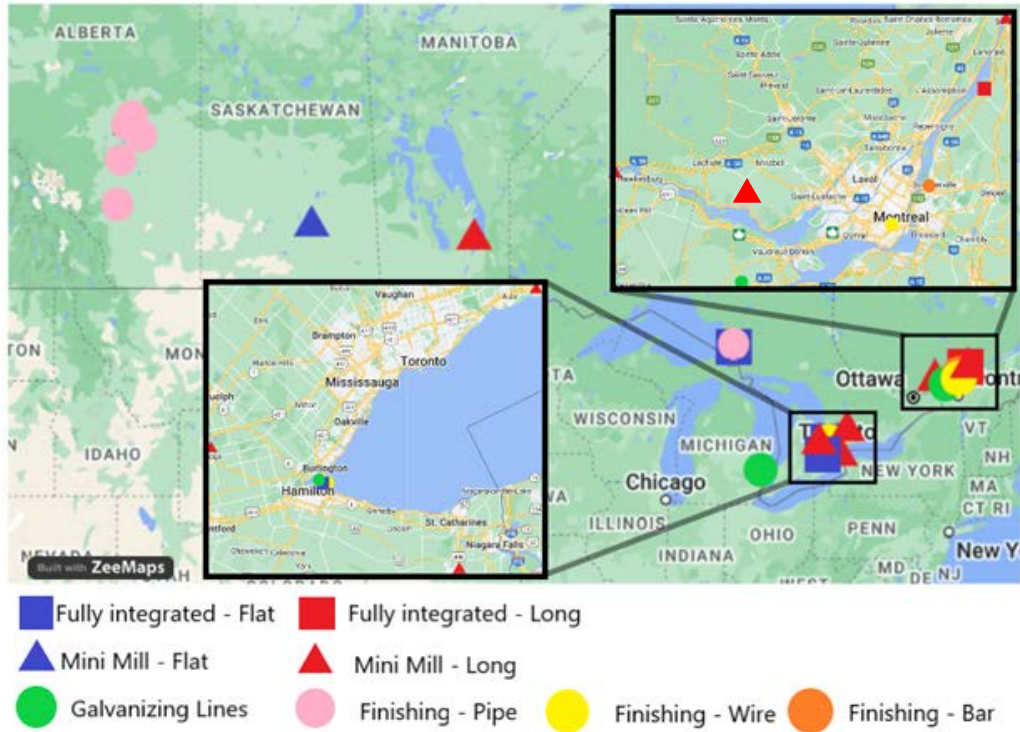
Figure 2.3. Steelmaking facilities in Canada

Table 2.1. Overview of steel companies in Canada

Region	Company Name	Number of Facilities	Type & Product
Western Canada	AltaSteel	1	Mini Mill – Long
Western Canada	EVRAZ North America Inc.	6	Finishing – Pipe
Western Canada	EVRAZ North America Inc.	1	Mini Mill - Flat
Western Canada	Gerdau Ameristeel Corporation	1	Mini Mill - Long
Western Canada	Tenaris S.A	3	Finishing – Pipe
Ontario	Algoma Steel Inc.	1	Integrated - Flat
Ontario	ArcelorMittal Dofasco	1	Integrated – Flat + Galvanizing Lines
Ontario	ArcelorMittal Long Products	1	Finishing - Wire
Ontario	Atlas Tube	1	Finishing – Pipe
Ontario	Gerdau Ameristeel Corporation	2	Mini Mill - Long
Ontario	Ivaco Rolling Mills	1	Mini Mill - Long
Ontario	Nova Steel	1	Finishing – Pipe
Ontario	Stelco Holdings Inc.	2	Integrated - Flat + Galvanizing Lines
Ontario	Tenaris Algoma Tubes	1	Finishing - Pipe
Ontario	Valbruna ASW Inc.	1	Mini Mill - Long
Quebec	ArcelorMittal Dofasco	1	Galvanizing Lines
Quebec	ArcelorMittal Long Products	1	Finishing - Wire
Quebec	ArcelorMittal Long Products	1	Finishing - Bar
Quebec	ArcelorMittal Long Products	1	Mini Mill - Long
Quebec	Nova Steel	1	Finishing – Pipe
Quebec	Rio Tinto, Iron & Titanium	1	Integrated - Long

2.1.2 Energy & Emissions Performance

The energy consumption and feedstock composition of the steel industry in Canada has evolved over time, with coke consumption generally decreasing, heavy fuel oils being almost entirely eliminated and natural gas consumption being volatile. The following figures use the energy consumption of the following NAICS industries: Iron and steel mills and ferroalloy manufacturing [3311], Steel product manufacturing from purchased steel [3312], Iron Foundries [331511] and Steel foundries [331514]. 2008 was removed from the following figure because no coal/coke usage was reported, which is likely an error. Looking at the master table/dataset, it seems like the values were not assigned from the master North American Industry

Classification System (NAICS) sector: Primary metal production. Although the numbers are flawed, they indicated a general tendency towards lower energy use, specifically lower coke and electricity use over time but did not indicate any major step changes in the industry since 1995.
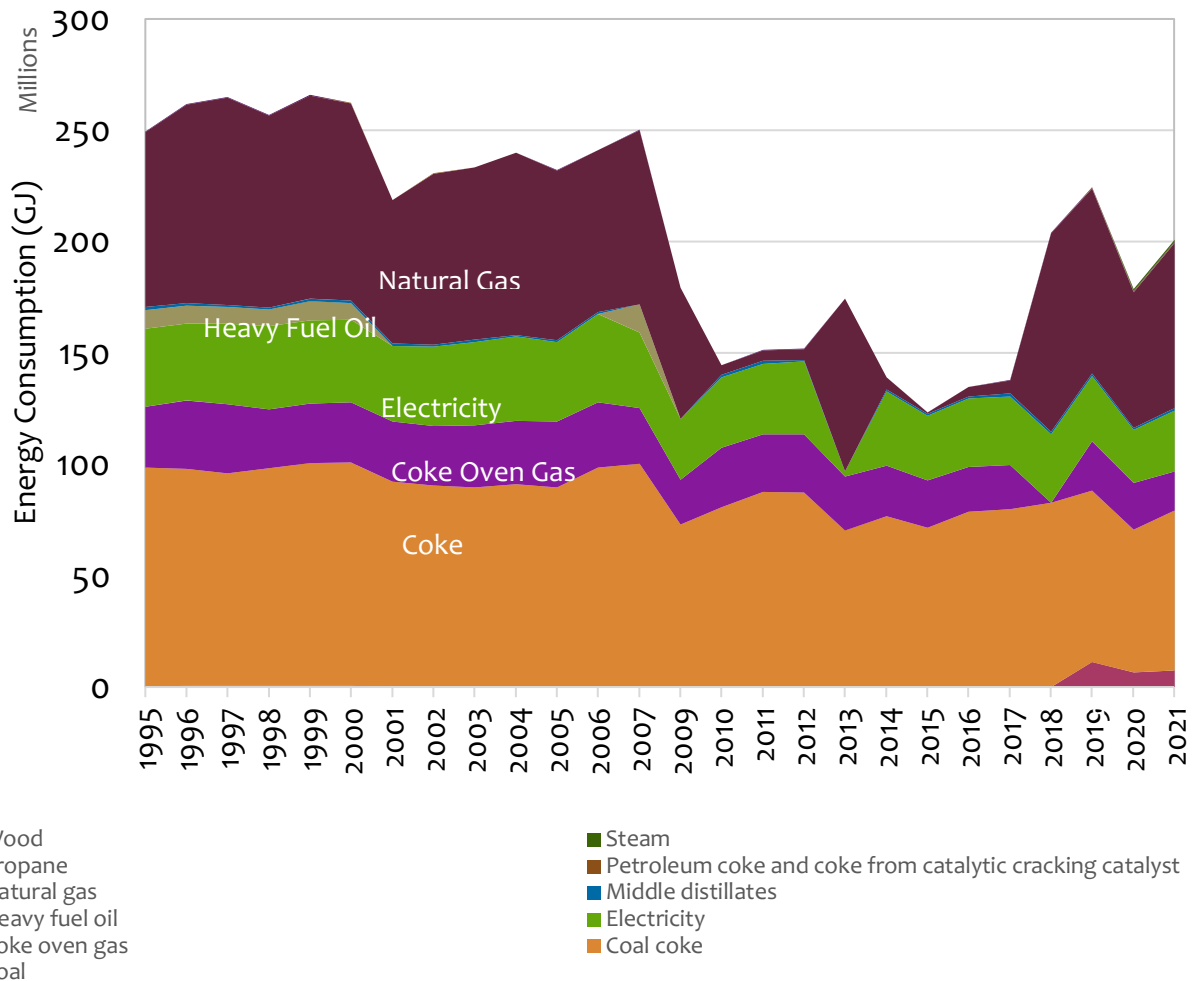
Figure 2.4. Energy consumption per fuel type of steel industry in Canada over time [12].

It is evident that there has been an increase in coal consumption in recent years. This is most likely attributed to the usage of pulverized coal injection (PCI) in the blast furnace as an alternative carbon source to coke. As coal does not have to undergo the energy-intensive coking process, this is a more energy/emission-efficient approach. Yet, there are limitations on the amount of coke that can be replaced. **Figure 2.4** also suggests that natural gas consumption decreased significantly between 2010 to 2016. However, this is most likely an error because the NAICS sector 'Iron and steel mills and ferroalloy manufacturing [3311]' reported 0 GJ of natural gas usage from 2010 to 2012 and 2014 to 2017 [12]. In addition, 2018 was the only year from 1995 to 2021 for which NAICS 3311 did not report any coke oven gas (COG) usage, likely another error. Finally, in 2013, there was no electricity use reported for NAICS 3311, another likely error. As a result,

the energy and emission values plotted for the years before 2019 do not allow for conclusions on the year-by-year performance of the Canadian steel sector but only serve to identify very general trends.

In addition, it is expected that the coke and coke oven gas consumptions will drop drastically, whereas electricity consumption will increase substantially when Algoma Steel converts to EAF operations and ArcelorMittal Hamilton converts fully to EAF operations with the addition of DR ironmaking [10,11].

From an emissions perspective, the Canadian steel industry has reduced its Scope 1 (fuel combustion and process emissions) and Scope 2 (electricity) GHG emissions over the last few decades [2,12,13]. Some of the Scope 2 reduction is simply due to reductions in grid emission intensities in Canada [13]. After 2019, both energy intensity and Scope 1 emission intensity decreased further, the latter possibly due to the use of pulverized coal injection replacing some coke consumption, as seen by the decreasing coke consumption intensity in **Figure 2.5**. The Scope 2 emission intensity decreases again due to the decreasing electrical grid emission factor.
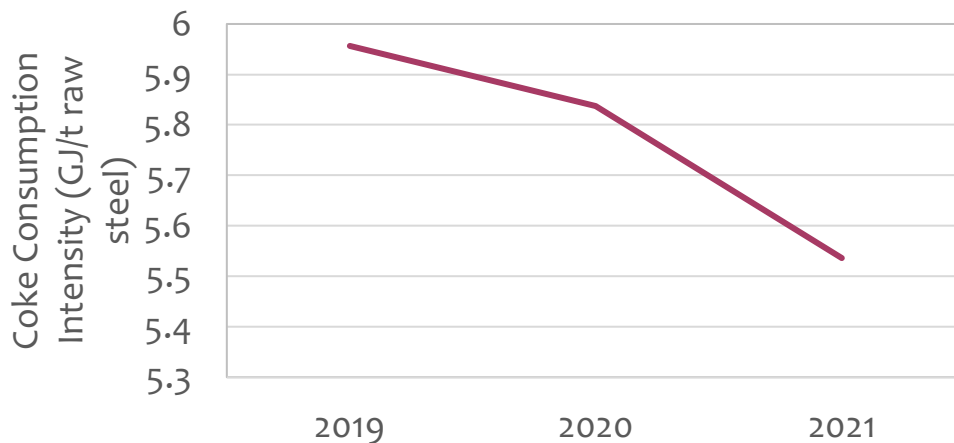
Figure 2.5. Coke consumption intensity of the Canadian steel sector over time [8,12].

2.2 Steelmaking Energy Use and GHG Emissions

2.2.1 Overview of Steelmaking

The following sections of this chapter explain but the energy numbers shown are only partially representative of Canadian mills. Moreover, each mill operates on somewhat different parameters and configurations, making comparisons more difficult (see also Section 2.2.6). This technical introduction to the subject of steelmaking will help the reader understand the four main processes involved in the traditional manufacturing of steel: raw material preparation, ironmaking, steelmaking, and hot rolling/steel shaping/finishing.
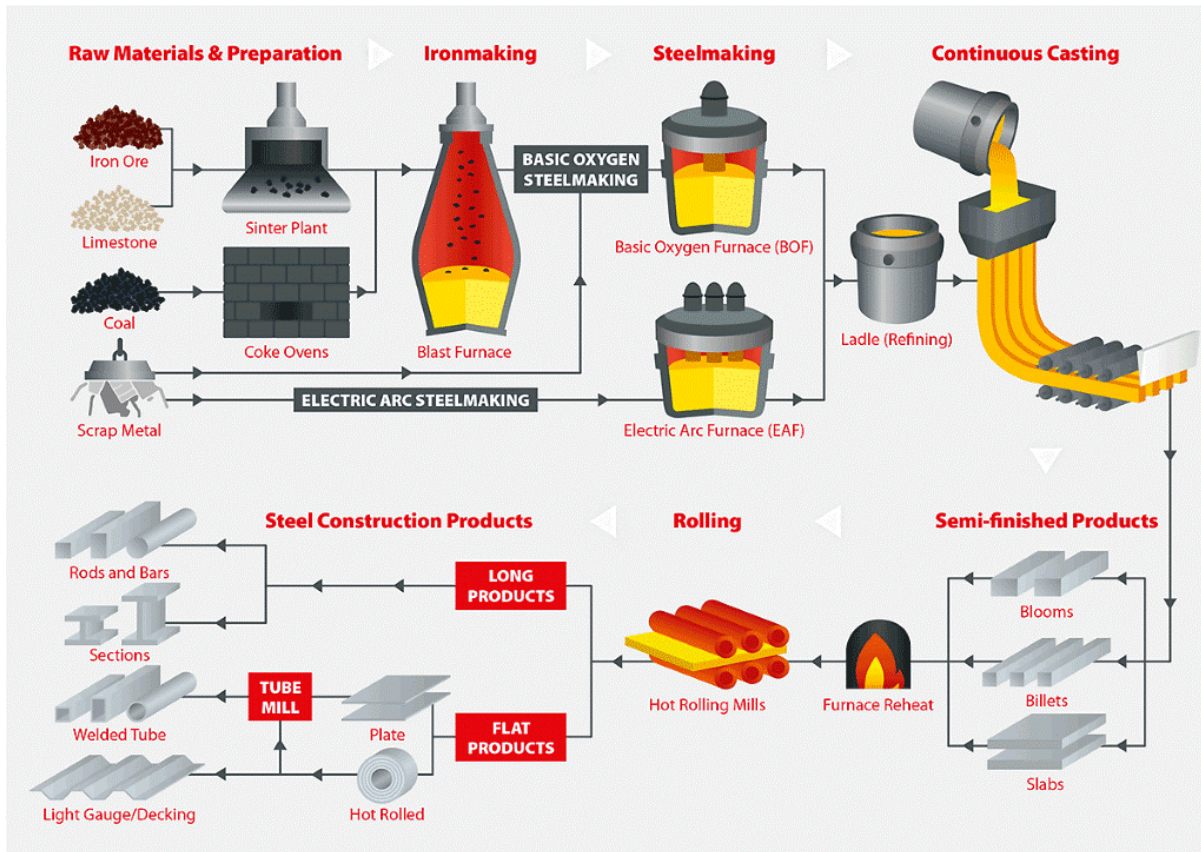
Figure 2.6. Overview of steelmaking processes [14].

The two main routes for steel production are the integrated route and the mini mill route. The integrated route is the traditional steelmaking process and includes sintering, cokemaking, blast furnace ironmaking and basic oxygen furnace (BOF) steelmaking. Currently, there are no sinter plants in Canada. The mini mill route employs an electric arc furnace (EAF) and is predominantly fed with scrap steel, with an option to have iron input to the process using direct reduction ironmaking (DRI). Both routes include ladle refining, casting, rolling, and finishing operations. Essentially - with the EAF route, the sinter/coke material preparation and blast furnace ironmaking processes can be substituted by a combination of DRI and scrap material preparation steps, and the EAF replaces the BOF.

2.2.2 Integrated Steelmaking Route

For the purpose of this report, the system boundaries for integrated steelmaking include cokemaking, BF ironmaking, and BOF steelmaking (with ladle furnace refining and continuous casting, where applicable), as well as on-site power/steam generation. The sintering and lime production processes are outside the scope of this analysis; hot rolling/finishing is dealt with separately. This is consistent with previous energy and emissions work by CSPA [2]. The following section will focus on cokemaking, BF ironmaking and BOF steelmaking. The ladle furnace, which is considered secondary steelmaking, and continuous casting are performed for both the integrated and mini mill routes so will be expanded on in subsequent sections.

The material flow and process boundaries for the integrated route can be seen in the figure below, which also shows the energy flow from the (off-site) power (electricity generation) plant to each process area.
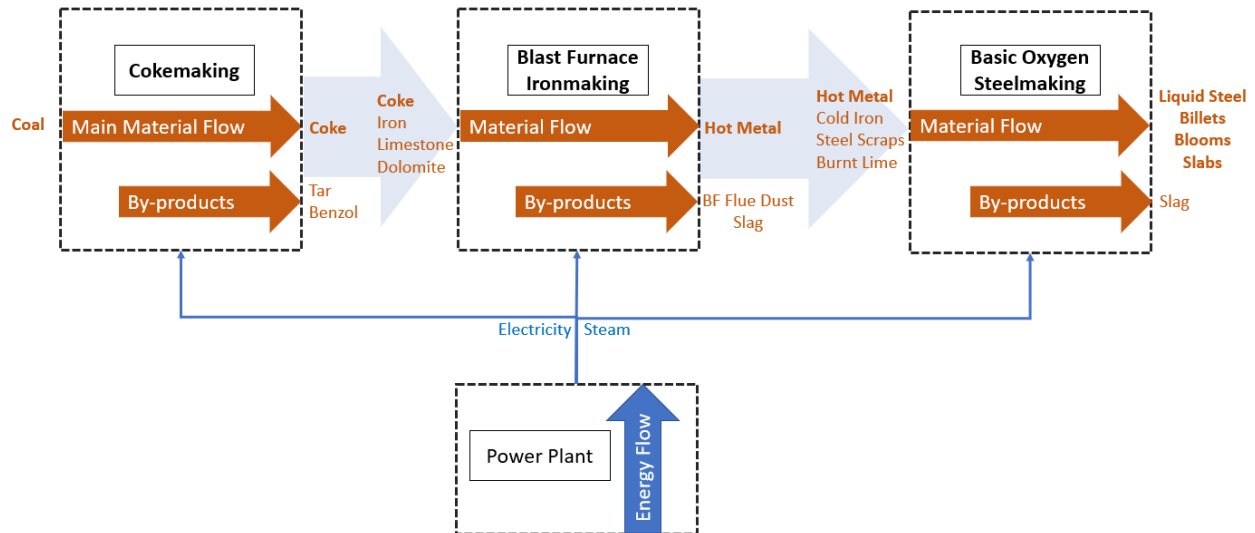
Figure 2.7. Boundaries and material flow for integrated route analysis.

Algoma Steel operates a Direct Strip Production Complex, which produces finished products straight from the continuous caster; thus, semifinished products are directly processed. As a result, semifinished products (billets, blooms or slabs) cannot be used as a production metric. Instead, the raw steel output from the BOF/ladle furnace was used to normalize the energy and emission intensities values.

Cokemaking

The purpose of the cokemaking step is to transform coal into coke for use as a reducing agent in the blast furnace. First, the coal is blended, crushed into a homogenous mixture and inserted into slotted ovens. It is then carbonized at high temperatures (~1100°C) in an oxygen-deficient environment to concentrate the carbon content of the material. As the coal is carbonized, the off-gases - called coke oven gas (COG) - are collected and utilized in other processes throughout the facility, such as power generation[15]. Once the entire mass is carbonized (soft plastic layers of coal have met in the middle of the oven), the incandescent coke mass is pushed from the oven and is either dry or wet quenched, producing coke. The figure below shows the energy and material flow commonly found in the cokemaking process.
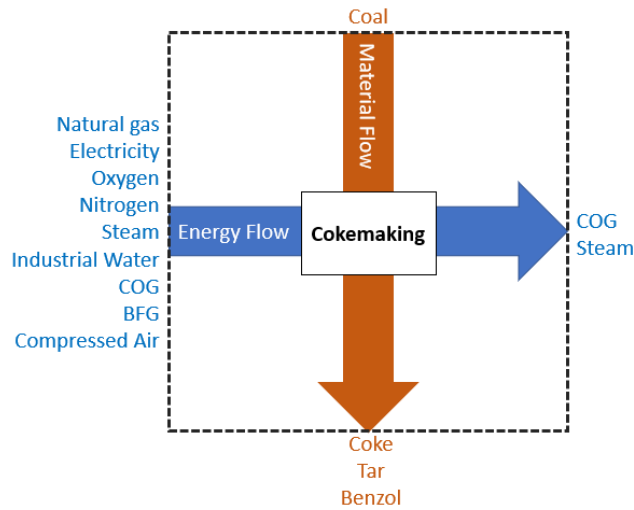
Figure 2.8. Energy and material flow for cokemaking

A typical mass and energy balance for a coke oven can be seen in the figures below, where green denotes inputs and red, outputs [16,17]. Note that the mass balance is for a heat recovery coke oven where the volatiles produced are combusted directly within the oven to provide additional heat [16].
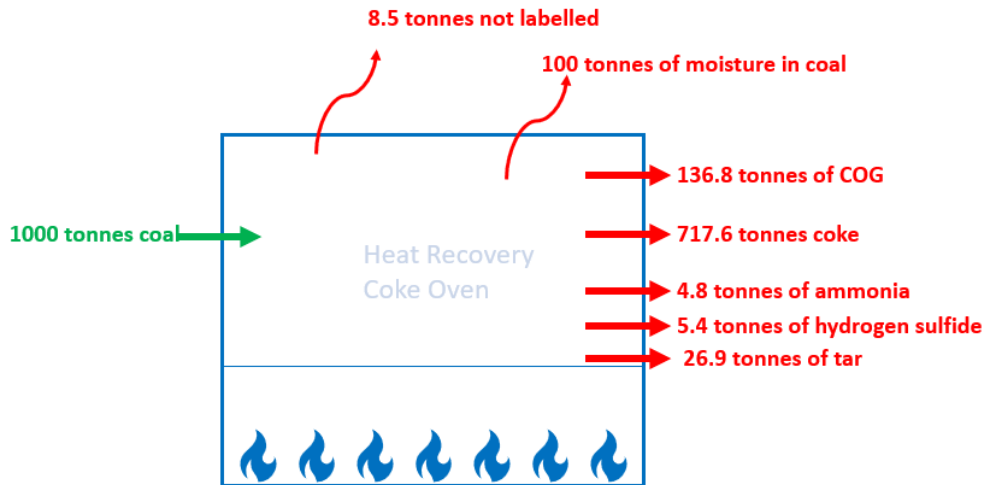
Figure 2.9. Mass balance for heat recovery coke oven
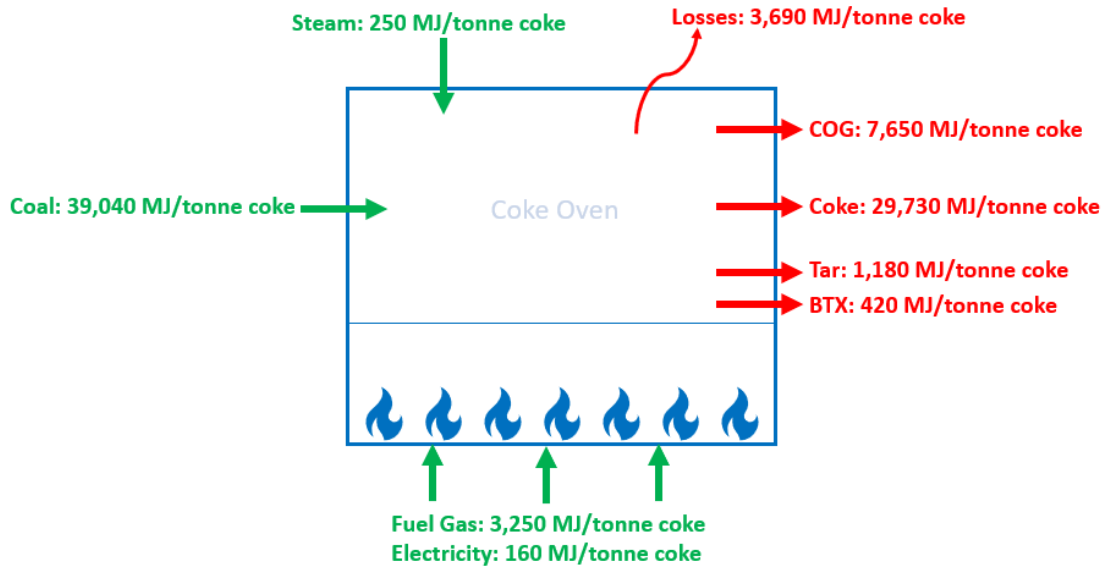
Figure 2.10. Energy balance for coke oven

Blast Furnace Ironmaking

The iron ore is combined with the coke (a reductant) and limestone in the blast furnace to create molten iron/pig iron. A blast furnace is a countercurrent reaction vessel where reactants are inserted through the top of the vessel, and hot air is blasted into the base of the vessel [18]. A constant stream of reactants falls downwards and reacts with the hot blast rising from the bottom of the vessel. The coke additives and limestone fluxes convert the waste materials in the charge (mainly silica and alumina) into a low melting point slag. The figure below shows the energy and material flow commonly found in the blast furnace ironmaking process.
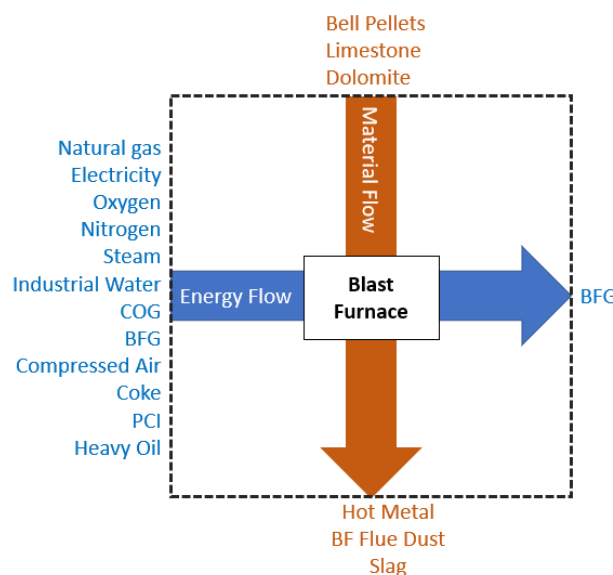
Figure 2.11. Energy and material flow for blast furnace ironmaking

At the bottom of the blast furnace, the molten slag separates from the molten iron due to its lower density. The slag and iron are tapped through holes at the bottom of the furnace at regular intervals. In an integrated steel mill, the molten iron is fed directly into the steelmaking process while the slag is transferred to slag pits and processed into useable materials. The blast furnace gas (BFG) that leaves the top of the vessel is a mixture of carbon dioxide, hydrogen, nitrogen, and carbon monoxide with a calorific value between 3,200 and 4,000 kJ/m³. After this exhaust gas is cleaned, it is used for a variety of purposes and is an important factor in keeping the operating costs of the blast furnace low [18]. A diagram showing the different reactions taking place within the blast furnace can be seen below, including the reduction of the iron ore (oxide) with the carbon (or carbon monoxide) from the coke. The reduction of iron oxide with carbon or carbon monoxide produces a significant amount of CO_2.

The Blast Furnace

Charge: iron ore, coke, limestone

Hot waste gases

Hot waste gases

250°C

700°C

Reduction of iron ore:
$3CO(g) + Fe_2O_3(s) \rightarrow 2Fe(l) + 3CO_2(g)$

Carbon dioxide reacts with coke:
$CO_2(g) + C(s) \rightarrow 2CO(g)$

Limestone decomposes and slag forms:
$CaCO_3(s) \rightarrow CaO(s) + CO_2(g)$
$CaO(s) + SiO_2(s) \rightarrow CaSiO_3(l)$
sand   slag

850°C

Hot air reacts with coke:
$C(s) + O_2(g) \rightarrow CO_2(g)$

Hot air blast

1500°C

Hot air blast

Molten Slag

Molten iron
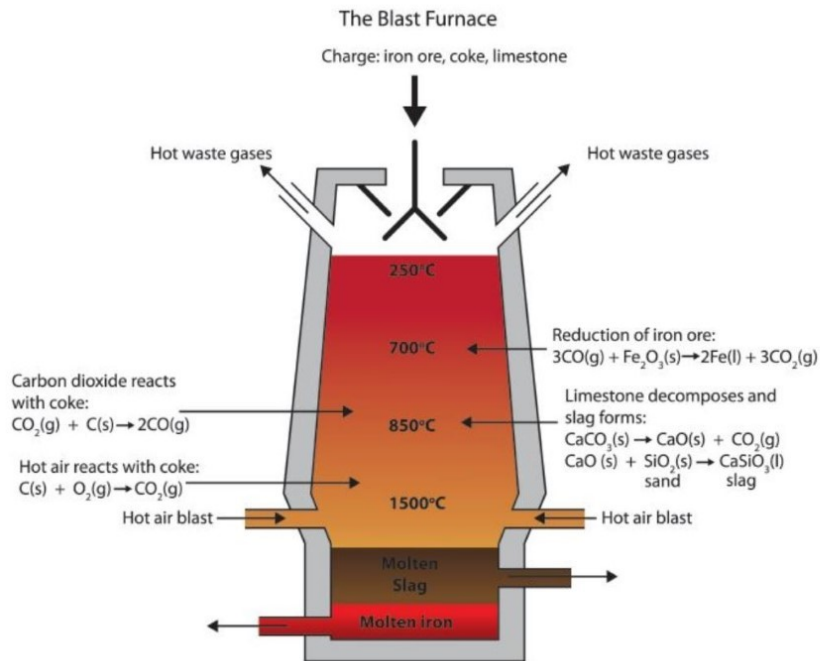
Figure 2.12. Reactions by zone in a blast furnace [18]

The material and energy balances for producing one imperial (long) ton of hot metal (i.e., 1 THM) for a modern large-scale ironmaking blast furnace are shown in the two figures below. The first figure shows some common operating conditions within the blast furnace, including temperature, pressure, injection rates of different inputs, the composition of by-products, etc.
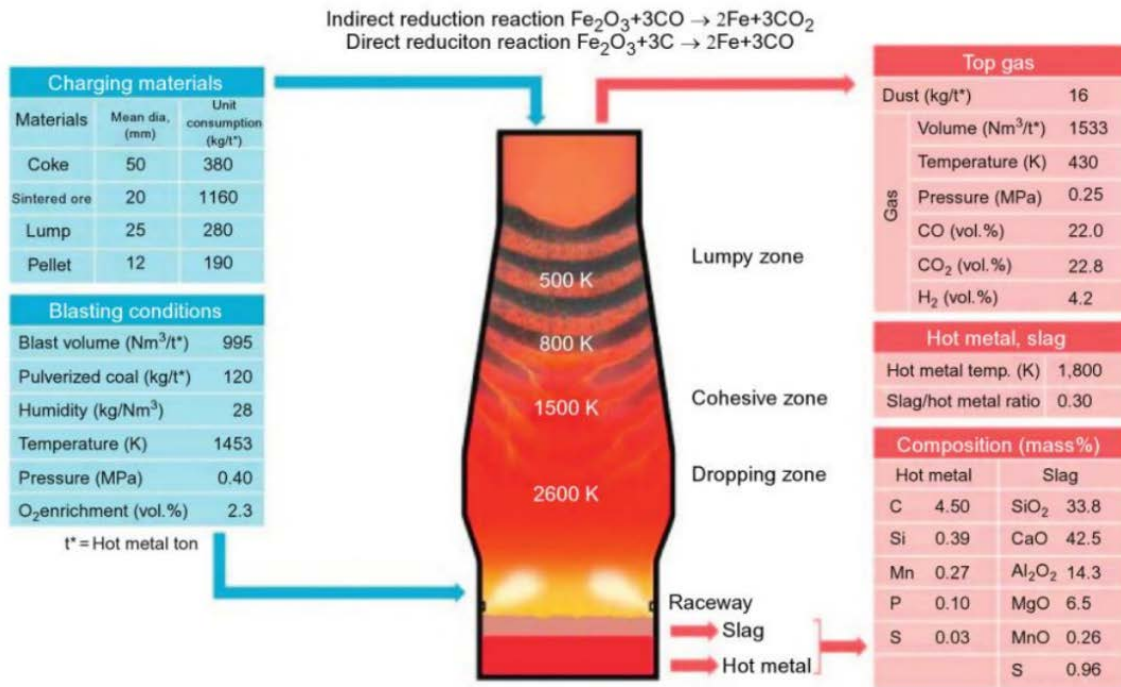
Figure 2.13. Mass balance and operating conditions of blast furnace [19]

The next figure shows the enthalpies associated with the inputs and outputs, including the amount of sensible enthalpy contained within the hot metal (iron) and slag outputs [19].
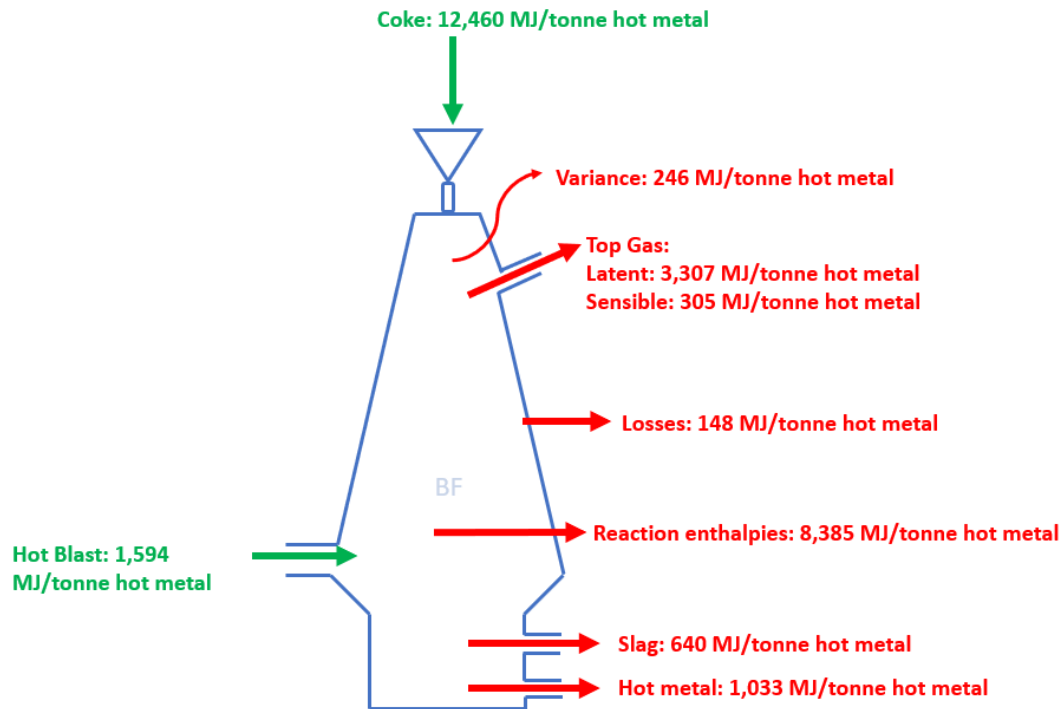
Figure 2.14. Energy balance of blast furnace

As this is a total energy balance, the heat input comes from the combustion of coke as well as the sensible heat of the hot blast. Roughly 60% of the total energy is used for the reduction of iron oxide ("reaction enthalpies"), 25% leaves the furnace as top gas (majority as chemical energy – latent heat), and 12% is contained in the hot metal and slag as sensible enthalpy. Furnace heat losses are generally very low (3-4%), though a 1% heat loss was determined for this example.

Basic Oxygen Furnace Steelmaking

The most common method of steelmaking is BOF Steelmaking, under which process the furnace is also known as a converter [14]. Molten iron is transferred from the BF to the BOF using a ladle. A lance is inserted into the top of the converter, and high-purity pressurized oxygen is blown onto the surface of the molten iron. This is known as the blowing cycle. The carbon and other unwanted impurities react with the oxygen in an exothermic (oxidation) reaction, causing an increase in the temperature of the molten iron (i.e., the overall reactions are self-sustaining) [14,20]. The temperature of the molten iron is controlled through the addition of colder steel scraps; this is known as maintaining the charge balance. Lime or dolomite are added to form a slag that absorbs the unwanted impurities. After approximately twenty minutes of the blowing cycle, the BOF is tilted to empty the steel through a tap hole; this process is known as tapping the steel [20]. The BOF is then turned upside down to empty out the remaining slag. The slag floats on top of the molten iron or steel because it is less dense, being a mixture of metal oxides and silicon dioxide. Variations of the BOF include bottom oxygen-blown vessels (OBM or Q-BOP) and combined blowing vessels (KOBM or LBE), which include an oxygen lance and a bottom feed of oxygen [21]. The figure below shows the energy and material flow commonly found in the BOF steelmaking process.
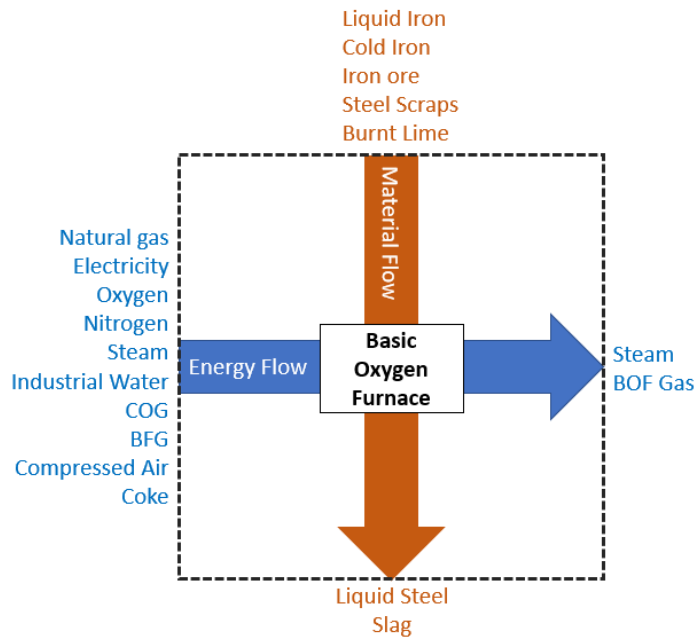
Figure 2.15. Energy and material flow for a basic oxygen furnace (BOF)

The Klöckner Oxygen-Blown Maxhütte or KOBM BOF is a combined blowing furnace where in addition to lance-delivered oxygen, oxygen is also blown into the vessel at the bottom [22]. Typically, 70% of the oxygen is delivered through the lance, while the other 30% is delivered through the bottom of the vessel through tuyeres (nozzles). This dual oxygen injection reduces yield losses and results in reduced steel oxygen contents [23]. The difference in the three types of BOFs is seen in **Figure 2.16**. A typical mass balance for a BOF can be seen in **Figure 2.17**. Green denotes inputs, and red, outputs [24,25].
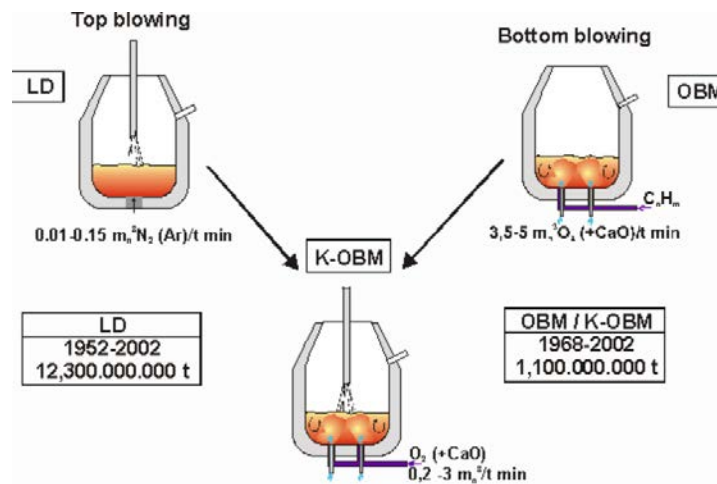
Figure 2.16. Different types of basic oxygen furnaces (BOF) [26]

1000 kg HM
193.54 kg scrap
99.31 kg lime

81.7 kg O$_2$

100.72 kg off gas

Basic Oxygen Furnace

188.13 kg slag

1091.18 kg steel
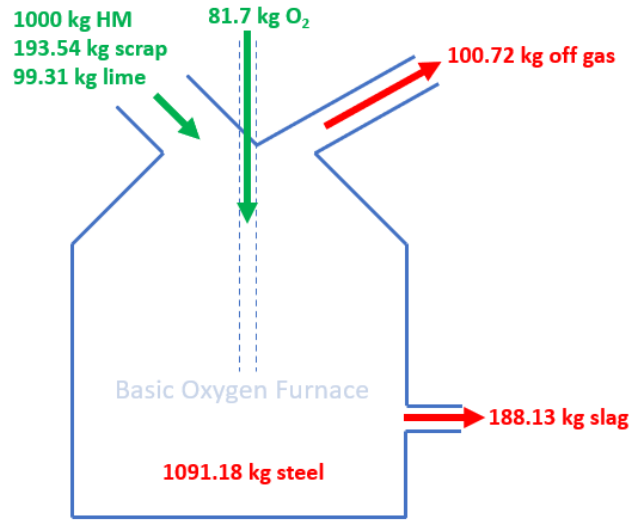
Figure 2.17. Mass balance for basic oxygen furnace (BOF)

As can be seen in the **Figure 2.18**, the heat in the BOF is supplied by the hot metal as well as the exothermic oxidation reaction. Most of the energy leaves the furnace as hot liquid steel, with the second biggest energy output consisting of the energy to melt the steel scrap and thermal losses.

Reaction: 911 MJ/tonne HM

Hot Metal:
1,239 MJ/tonne HM

Off gas: 156 MJ/tonne HM

Scrap melting & waste heat:
469 MJ/tonne HM

Basic Oxygen Furnace

Slag: 255 MJ/tonne HM

Steel: 1,271 MJ/tonne HM
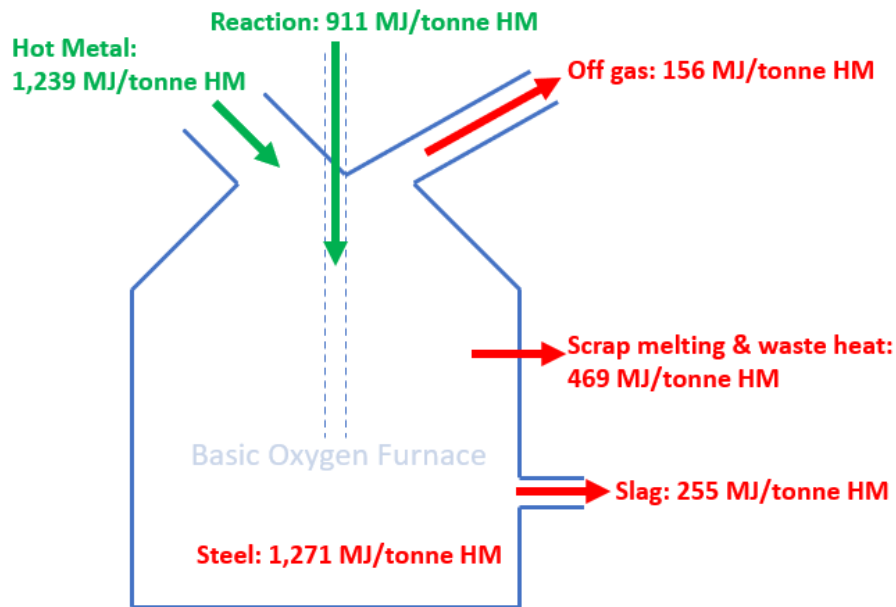
Figure 2.18. Energy balance for basic oxygen furnace (BOF)

After the BOF, the liquid steel undergoes secondary steelmaking and continuous casting, both of which are processes that are shared between the two main steelmaking routes.

2.2.3 Mini Mill Steelmaking Route

The mini mill route includes EAF steelmaking, ladle refining and continuous casting. The material preparation for scrap and pelletizing for DRI operations is outside the scope. The material flow and process boundaries for the mini mill route can be seen in the figure below. To be consistent with the integrated route, the raw steel output from the EAF/ladle furnace will be used to normalize the energy and emission intensities values.
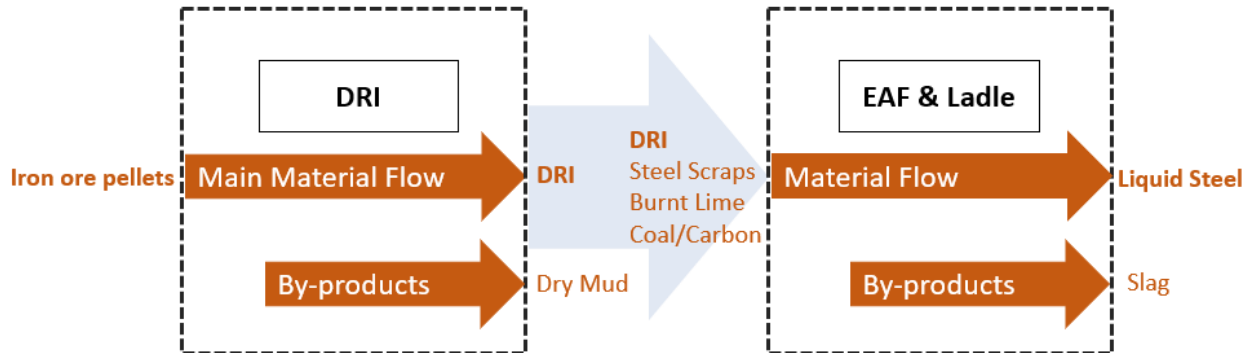
Figure 2.19. Boundaries and material flow for mini mill route analysis

Direct Reduction Ironmaking

In the DRI process, the direct reduction of iron involves the removal of oxygen from iron ore without melting it (i.e., keeping the iron ore in its solid state) [27]. Carbon monoxide or hydrogen gas are used as reducing agents and are reformed from natural gas, syngas or coal. Pure hydrogen gas can also be used as the sole reducing agent, as seen with the Midrex H_2 DRI furnace [28]. The chemical reactions when either hydrogen or carbon monoxide are used can be seen below [27].

With H_2:

$$3Fe_2O_3 + H_2 \rightarrow 2Fe_3O_4 + H_2O$$
$$Fe_3O_4 + H_2 \rightarrow 3\ FeO + H_2O$$
$$FeO + H_2 \rightarrow Fe + H_2O$$

With CO:

$$3Fe_2O_3 + CO \rightarrow 2Fe_3O_4 + CO$$
$$Fe_3O_4 + CO \rightarrow 3\ FeO + CO_2$$
$$FeO + CO \rightarrow Fe + CO_2$$
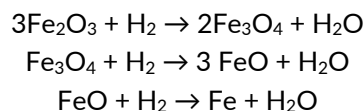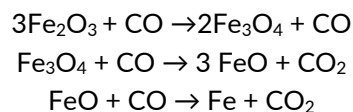
As can be seen in the reactions above, when hydrogen is used as the reducing agent, the by-product is water rather than CO_2, which is produced when carbon monoxide is used as the reducing agent. For traditional ironmaking, carbon monoxide is used primarily as the reducing agent, resulting in significant CO_2 emissions. As a result, the use of hydrogen in DRI has received a lot of attention as an alternative low-emission

ironmaking process for EAFs. The figure below shows the energy and material flow commonly found in the DR ironmaking process.

The two main processes for DRI are natural gas-based shaft furnace processes and coal-based rotary kiln furnaces. The gas-based shaft furnace process accounted for 82% of 2016 global direct iron reduction production, including the Midrex® and Energiron processes that use iron pellets/lumps as feedstock [27]. The coal-based rotary kiln furnaces, used mainly in India, accounted for 17.5%. The gas-based shaft furnaces are packed bed reactors, where hot gas flows upwards, and the solid iron falls downwards to maximize reduction efficiency [29].
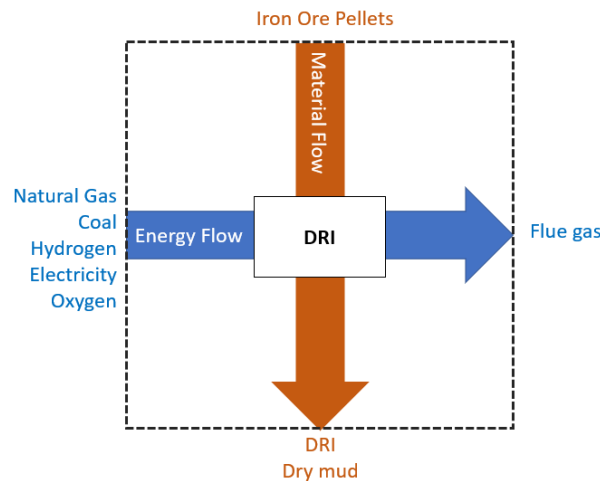
Figure 2.20. Energy and material flow for direct reduction (DR) ironmaking

The Midrex process, generally considered a shaft furnace process, has three main operations: natural gas reforming, gas preheating and iron ore reduction [29]. The exhaust gas that leaves the top of the shaft furnace is cleaned and cooled by a wet scrubber and recirculated. The top gas that contains CO_2 and H_2O is pressurized, mixed with natural gas, preheated, and fed into a reformer furnace to be reused as a reducing agent. The sensible heat of the flue gas that leaves the reformer is used to preheat the feed gas mixture and the burner combustion air. This allows the Midrex process to operate in a simple closed loop, which minimizes energy consumption and reduces the number of moving parts within the plant. The Midrex process can produce Hot Direct Reduced Iron (HDRI) and Cold Direct Reduced Iron (CDRI) [30]. CDRI is cooled in the lower part of the Midrex shaft furnace to around 50°C. HDRI is left at 650°C and transported to a nearby EAF to take advantage of the sensible heat [30], although it is noted that some facilities do not have conveyors capable of transporting HDRI. Diagrams for two of the most popular shaft furnace DRI products can be seen in the figures below.
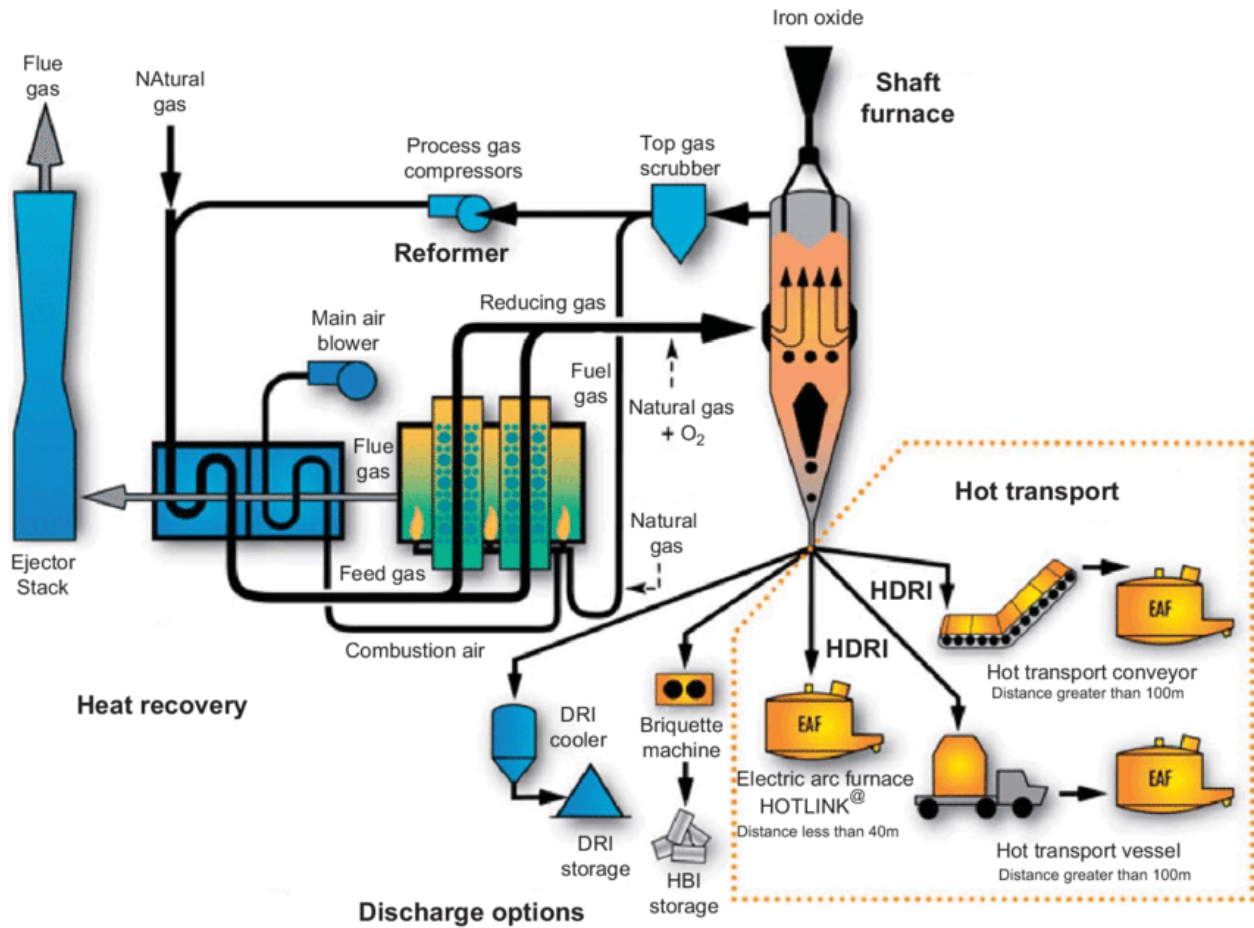
Figure 2.21. Process flowsheet for the Midrex DRI process [27]
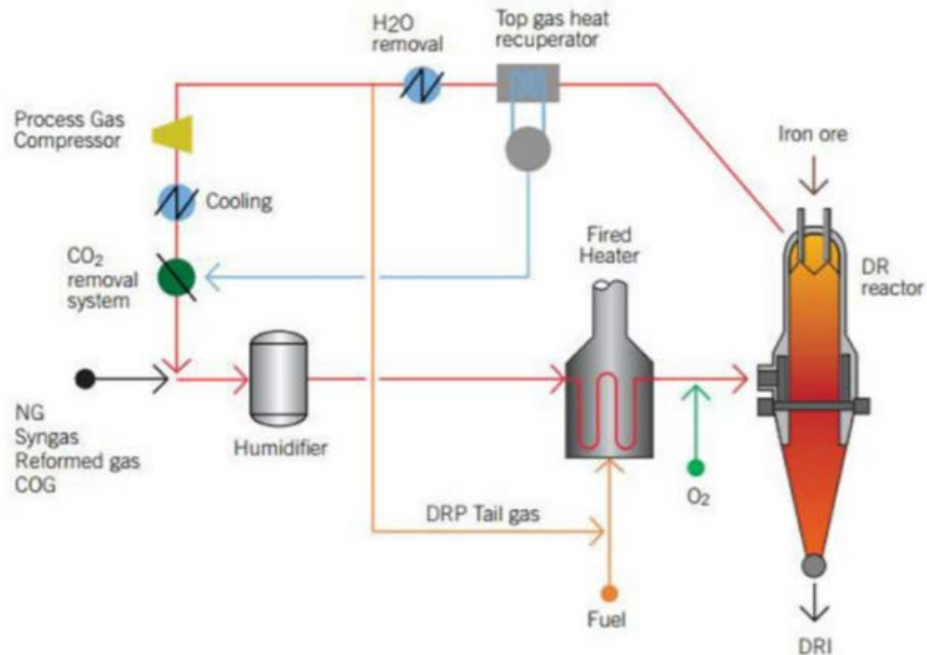
Standard Energiron process flowsheet

Figure 2.22. Process flowsheet for the Energiron DRI process [27]

A premium form of direct reduction iron is called Hot Briquetted Iron (HBI), which has been compacted at 650+°C and has a density greater than 5,000 kg/m^3 [31][53]. HBI was developed to solve the issues with shipping DRI, which is extremely porous and, therefore, very reactive. The primary use for HBI is in EAFs, but it can also be used as a trim coolant in BOF or as feedstock for a blast furnace [31].

The heat balance for the Midrex process producing CDRI is shown in the figure below, including the additional oxygen and electricity requirements that are outside the heat balance [19]. Natural gas is being used in two ways: as the input to the reformer to produce the reducing agent H$_2$ and CO, as well as to heat the reformer. The flue gas leaving the reactor is usually recycled within the process and fed back into the reformer to act as a reducing agent.
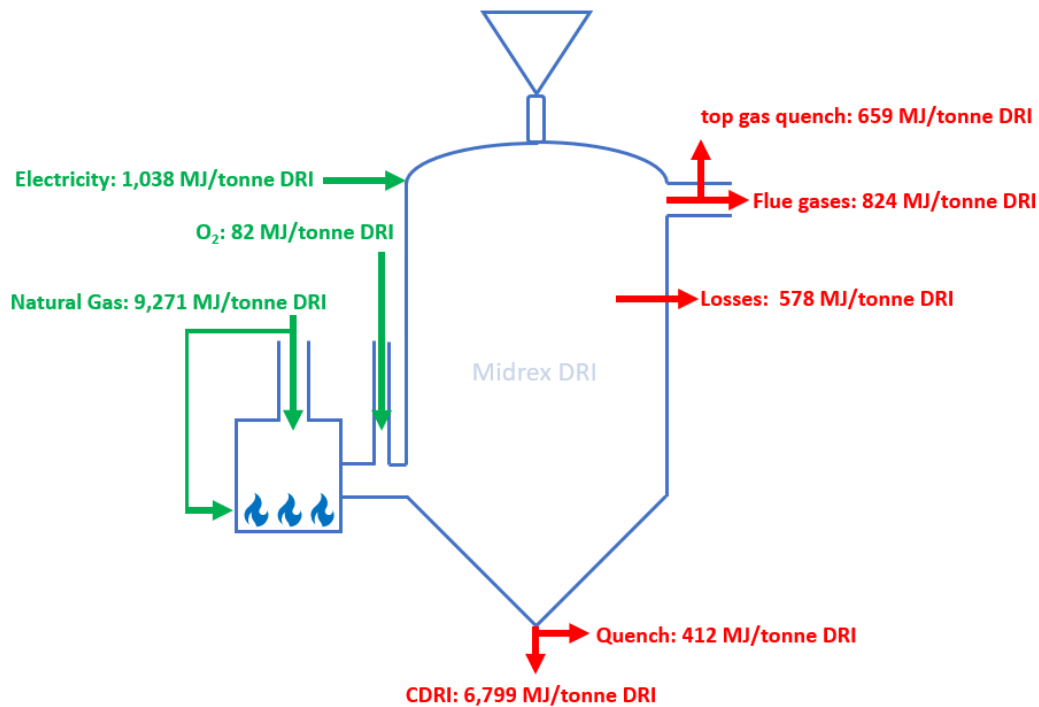
Figure 2.23. Heat balance with additional electricity and oxygen energy consumption for Midrex DRI

Electric Arc Furnace Steelmaking

The next step is to use the DRI and/or recycled steel scrap in an EAF to produce steel. EAF steelmaking utilizes an electric arc, rather than combustion heat, to melt and produce steel. Some EAFs operate purely on recycled steel scrap as the material input, while others utilize DRI and steel scrap at varying ratios as inputs. The steel scraps/DRI (or charge) are placed in the EAF with a removable lid that contains graphite electrodes [14].[1] After the steel scraps are inserted into the EAF, the lid is lowered, and an electric arc is created between the electrodes by passing a strong electric current through the charge. The resulting heat created by the electric arc melts the steel scraps. Lime and fluorspar are added, and oxygen is blown into the melt to aid in the creation of the slag, which will contain the oxidized impurities. **Figure 2.24** shows the energy and material flow commonly found in the EAF steelmaking process.

A sample of the molten steel is taken, and the EAF is tapped to remove the steel when the appropriate temperature and purity have been reached. As some EAFs use 100% scrap as feedstock, this greatly reduces the energy consumption of the mini mill route when compared to traditional steelmaking techniques that need to first reduce iron ore. Another benefit is the rapid stop-and-start capabilities of the EAF.

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[1] EAF using alternating current has three electrodes; whereas DC-EAF has only one.
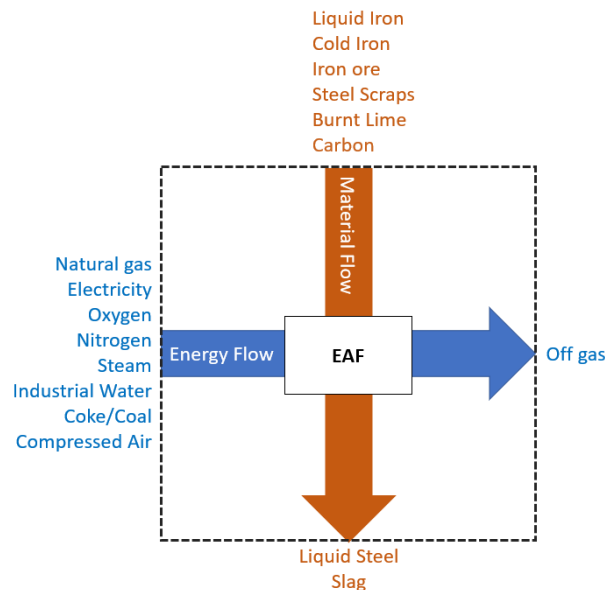
Figure 2.24. Energy and material flow for electric arc furnace (EAF) steelmaking

An Eccentric Bottom Tapping (EBT) furnace is a type of EAF that uses a tap hole on the bottom of the vessel rather than using a spout method like traditional EAFs [32]. The furnace is tilted at an angle of 25 degrees during the melting process and is believed to increase the water-cooling rate of the furnace material, therefore decreasing the refractory material and electrode consumption rate [32]. This slag-free tapping technique reduces tap-to-tap times, thus allowing the production of more refined steel [32]. A comparison of an EBT (denoted "B") and a traditional EAF (denoted "A") is shown below.

Figure 2.25. Different types of electric arc furnaces (EAF) [32].

As can be seen in **Figure 2.24**, the EAF often utilizes natural gas/coke/coal as an alternative energy source to reduce the amount of electricity required to melt the charge but also to perform further reductions of oxides contained in the charge. The use of natural gas instead of electricity can result in GHG emission reductions for countries/provinces that produce electricity primarily from coal. In addition, there is pure carbon that is injected into the EAF together with oxygen gas to generate CO bubbles within the slag, with the goal of creating a foamy slag [33]. This foamy slag improves the overall energy performance of the EAF while reducing furnace wear [33]. There has been research into replacing the injected carbon and coal/coke in an

EAF with other carbon carbon-bearing sources, such as biomass-based alternatives or rubber/plastic-based alternatives, to reduce process emissions associated with EAF steelmaking [33][56].

A typical mass and energy balance for an EAF can be seen in the figures below, where green denotes inputs and red, outputs [19,34,35]. The first mass balance figure and the energy balance figure are for a scrap-only EAF and are very detailed, while the second mass balance figure is for an EAF operating on both scrap and HDRI but is not as detailed.
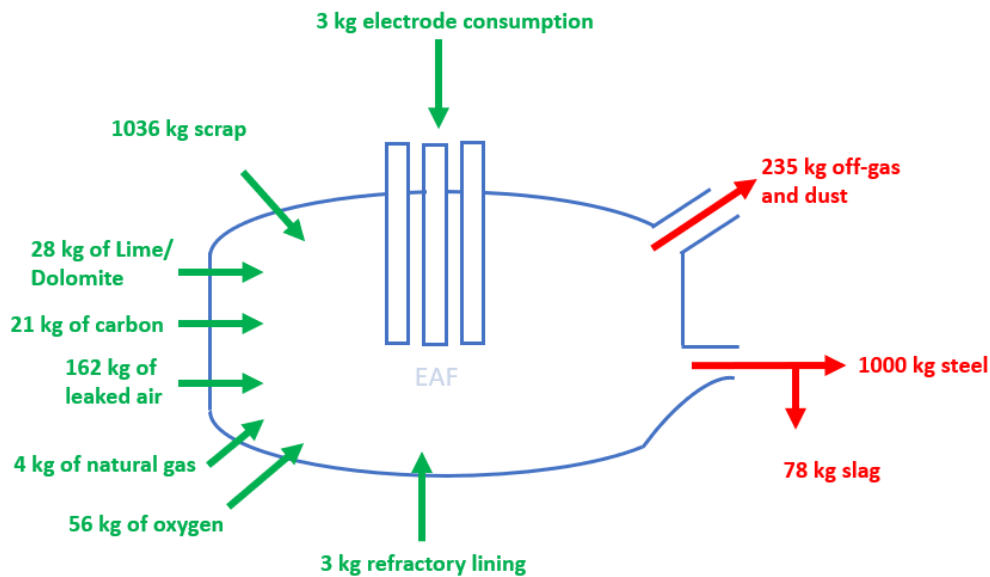
Figure 2.26. Detailed mass balance for scrap-only electric arc furnace (EAF) based on [34]
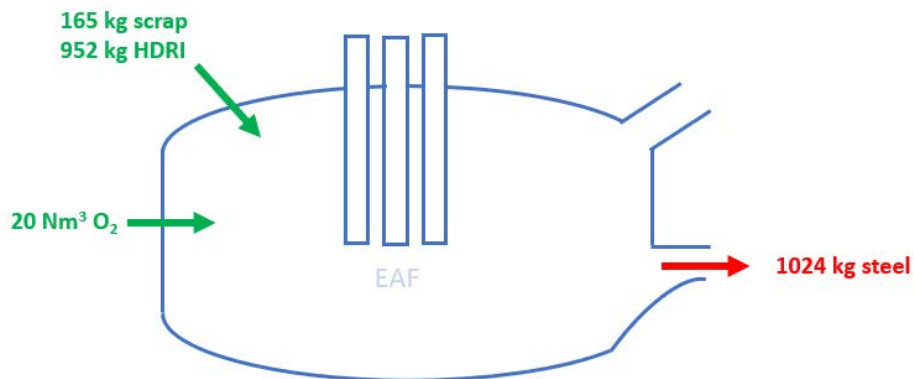
Figure 2.27. Mass balance for scrap + DRI electric arc furnace (EAF) based on [35]
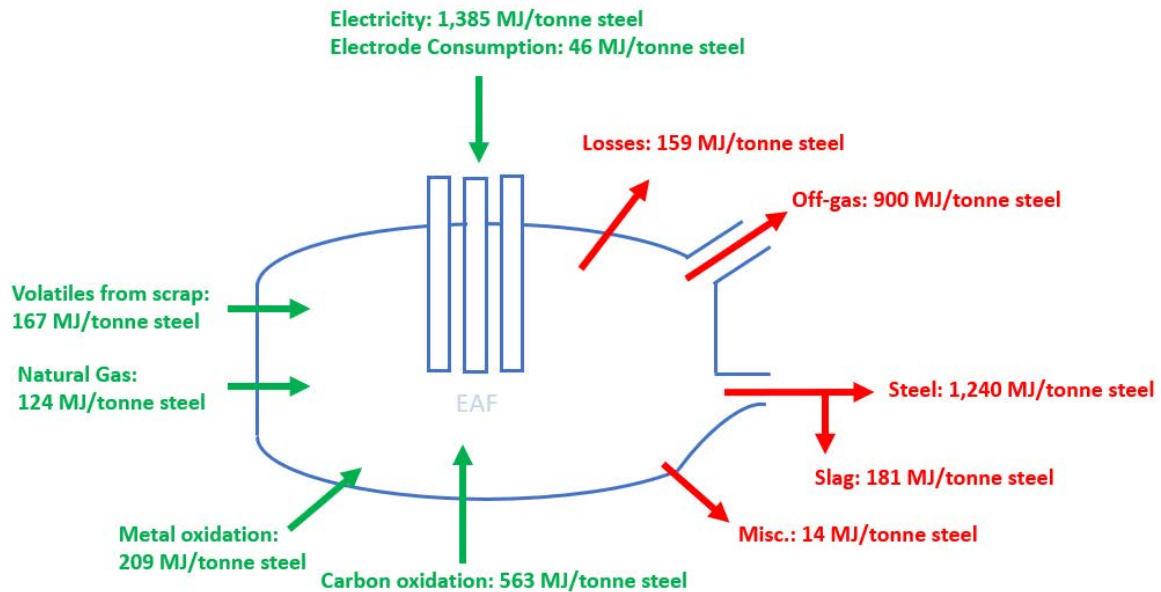
Figure 2.28. Energy balance for a scrap-only EAF based on [19]

2.2.4 Secondary Steelmaking and Continuous Casting

Secondary steelmaking using a ladle furnace and the continuous casting process are shared between the two main steelmaking routes. The ladle furnace is a secondary steelmaking device that has two main purposes: first, to perform secondary refining to alter the final temperature and chemical composition of the steel and second, to transfer steel from the steelmaking device to the casting process to allow for continuous steelmaking and casting operations [36]. Secondary refining includes vacuum degassing to remove unwanted dissolved gasses, Argon Oxygen Decarburization (AOD) or Vacuum Oxygen Decarburization (VOD) to produce stainless steel, etc. [37]. With continuous casting, the liquid steel is transferred from the ladle furnace into a collection vessel called the tundish. Gravity then pulls the liquid steel from the tundish down into the continuous caster, which is cooled and solidified into semifinished products using water-cooled copper molds (**Figure 2.29**).
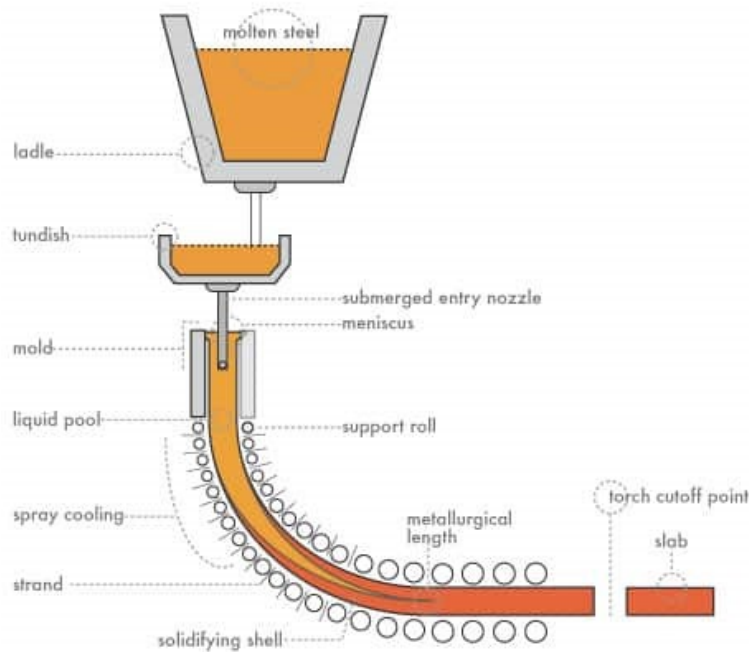
Figure 2.29. **Continuous casting diagram** [38]

2.2.5 Reheating and Hot Rolling

One of the least intrusive ways to implement hydrogen in the steel industry is to use it as a fuel for reheat furnaces. Steel is rolled into finished products at high temperatures as its resistance to shaping is reduced at elevated temperatures (i.e., annealing) [14]. After the semifinished products are heated to 1,200°C in a reheat furnace, they are squeezed through a set of rollers. These rollers are housed in a stand and arranged in pairs. The steel must be continually run through the rolls while reducing the thickness, and thousands of tonnes of force must be exerted to change its shape. There are two main classes of finished products: flat products and long products [14]. Long steel products are made from "blooms" or "billets" and include rods, bars/coil sections, wire, nails, and small-diameter seamless pipes. Examples of long steel include rebar, which is used to increase tensile strength of concrete, and Merchant Bar Quality (MBQ) which is a low-quality carbon steel typically used in structural applications [39]. Flat steel products are made from steel slabs and include plates, strips, hollow sections, large-diameter welded pipe and structural beams [40]. To roll a flat product, two horizontal rollers are set one above the other inside an open housing, while long products are created using a series of angled rollers. If the steel is going to be used as Oil Country Tubular Goods (OCTG) or line pipe, it needs to be formed into pipes instead. OCTG and line pipe can be produced with steel from either the steelmaking process or semifinished steel product (hot rolled coil for electric resistance welded pipe and billet for seamless pipe).
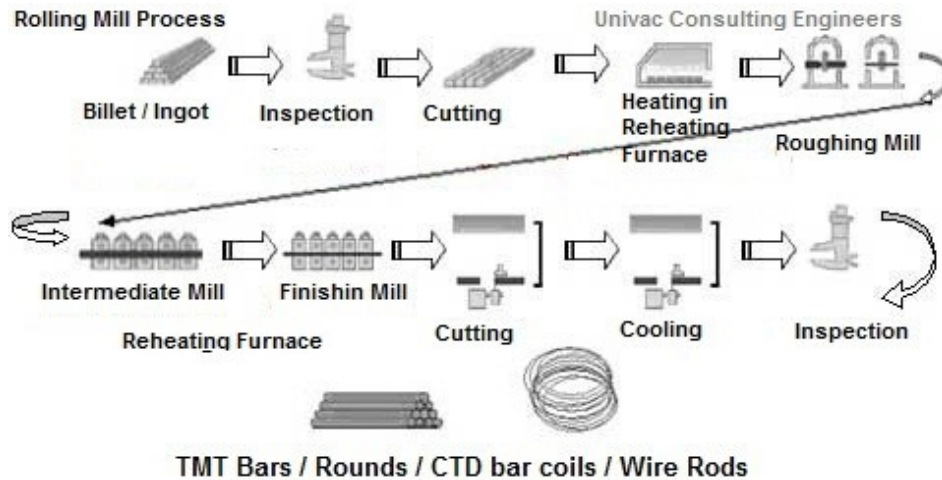
Figure 2.30. Hot rolling diagram [41]

2.2.6 Route Performance Comparison

General

In an integrated steel mill, around 95% of the energy requirement is provided as solid fuel (usually coal/coke), 3-4% as gaseous fuels and 1-2% as liquid fuels [19]. For an integrated steel mill that uses a BF-BOF process, around 75% of the energy usage of the coal is attributed to the blast furnace. This is due to blast furnaces using coal/coke as both a fuel and a reducing agent. Due to the high energy demand of BF ironmaking and cokemaking, past efforts have focused on making these processes more efficient, with less research on BOF improvements, as it is already a fairly efficient device. The focus on BF/cokemaking has seen a reduction over time in the coke consumption of the blast furnace, as seen in the following table (where THM is imperial long tons of hot metal produced).

Table 2.2. Reduction in coke rate over time [19]

Year	Coke Rate (kg/THM)	Injectant (kg/THM)	Total Reductant (kg/THM)	Comments on BF Operation Including Major Changes Made
1950	1000	0	1000	Lean local ores were used
1965	600	0	600	Rich seaborne ores began to be used
1970	525	50	575	Oil injection, high blast temperature operation, oxygen enrichment were practiced
1980	500	50	550	High top-pressure operation along with improved burden distribution facilities and permeability control
1990	400	125	525	Increased coal injection as well as improved sinter, coke quality
2000	325	175	500	Increased coal/gas/oil/tar injection
2010	250	250	500	Continued use of metallics like DRI in the burden

For each of the processes that make up the integrated and mini mill routes, the energy and emission intensities are summarized in **Table 2.3**. Each process is defined in terms of megajoules per ton of product produced (i.e., for cokemaking, it is 5800 MJ per imperial long ton of coke produced). Therefore, if the goal is to combine the processes to analyze the integrated and mini mill routes as a whole, further conversion factors are necessary to ensure all the processes are defined using a common unit (i.e., megajoules per ton of steel produced).

Table 2.3. Summary of energy and emission intensity values per process [19]

Process	Energy Intensity (MJ/ton Product)
Pelletizing	1900
Sintering	2700
Cokemaking	5800
Blast furnace	12780 (Hot metal)
	14000 (Pig iron)
Gas-based direct reduction	9956 (CDRI)
	10266 (HDRI)
Basic oxygen furnace	300 (Full heat recovery)
	1900 (No recovery, and pig iron)
	3200 (No recovery, and hot metal)
Electric arc furnace	5885 (100% Scrap)
	8036 (50:50 CDRI:scrap)

Process	CO_2 Intensity (kg CO_2/ton Product)
Pelletizing	120
Sintering	200
Cokemaking	320
Blast furnace	1450
Gas-based direct reduction	518
Basic oxygen furnace	(Full heat recovery) 62
	(No recovery) 222
Electric arc furnace	(Pure scrap) 311

As mentioned previously, due to the mini mill route using a lot of steel scrap (recycled material) as an input, the energy intensity is often far lower. However, the ratio of scrap to DRI that is input into an EAF strongly influences the energy and emission performance of mini mills. If a very low scrap ratio is used, a lot of DRI would be required, thus increasing the energy intensity.

An alternative boundary that includes steel scrap preparation for the mini mill route and its effect on the energy intensity can be seen in the figure below for an open-hearth furnace, a technology not used in Canada and not widely used worldwide [19]. The blue box contains the integrated route, while the green box contains the mini mill route. A general assumption used in this analysis for non-heavily processed materials is that they have no energy/emission component. For example, lump iron ore fed directly into the ironmaking process is assumed not to require additional pre-processing at the mill relative to the sinter/pellets, which have been processed into pellets. A similar principle is applied for scrap metal compared to hot metal, DRI, etc.

The energy intensity range for 100% scrap EAF production is 9.1 to 12.5 GJ per ton of steel, including scrap preparation. A value of ~6 GJ per ton of steel was seen previously when no scrap preparation was included. Therefore, it is likely that the scrap preparation is a significant energy consumer when analyzing the mini mill route. However, if low-GHG electricity is used, it will have a small influence on indirect GHG emissions.
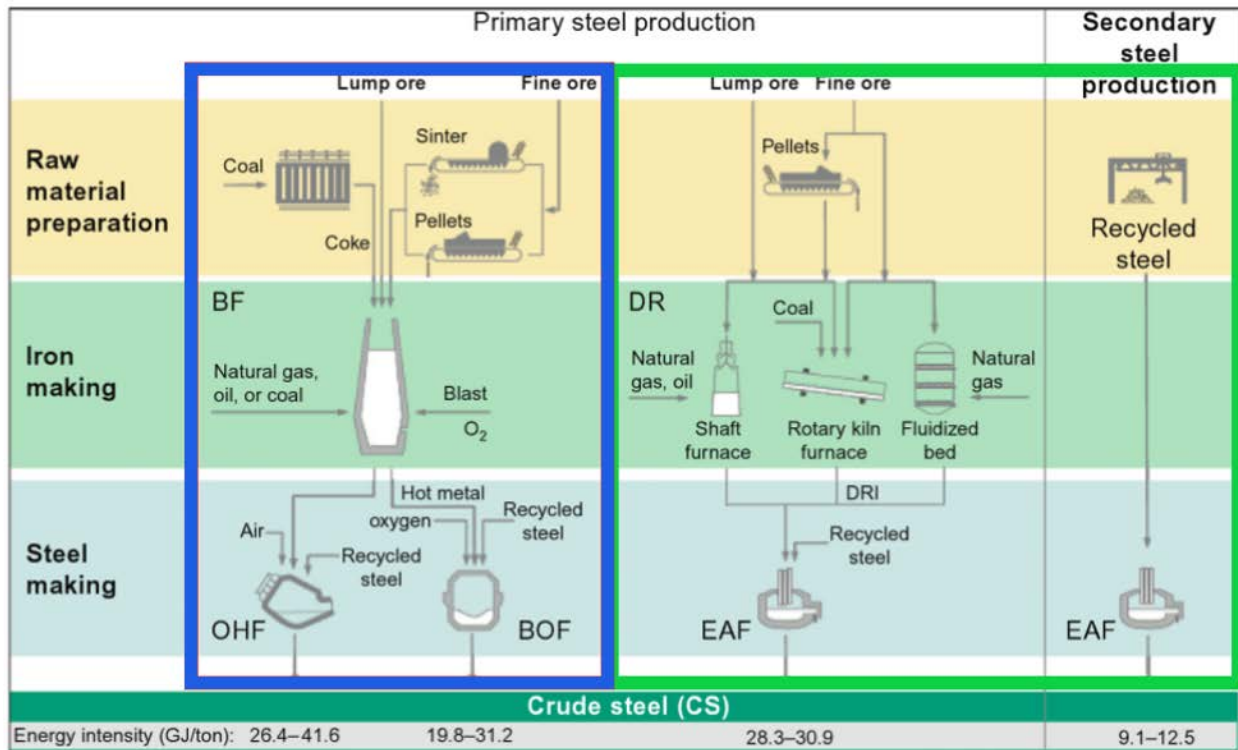
Figure 2.31. Additional literature values for energy intensity by route [19]

2.2.7 Canada-Specific Results

For the analysis completed in this section, CSPA-supplied production data, energy data, and emission factors for 2018 were used that were provided for a previous report [2]. To allow for scaling with the production values seen in subsequent years, intensity-based values will be provided (i.e., GHG emissions per tonne of raw steel, etc.). The boundaries of the integrated facilities for this analysis include: cokemaking, BF ironmaking, BOF steelmaking (including ladle furnace refining and continuous casting, where applicable), as well as any on-site electricity generation and boilers. Any hot rolling/casting, finishing operations, sintering, coal storage, lime production etc., are outside the boundaries of this analysis. The boundaries for the mini mill process focus solely on the EAF steelmaking process, including the EAF, ladle furnace and continuous casting. It will therefore exclude hot rolling/casting, finishing operations, and DRI. For ArcelorMittal Dofasco, the EAF steel production/consumptions were included in the EAF route, while the cokemaking, ironmaking, BOF steelmaking and power plant/boiler house were included in the BOF route.

For both routes, the same electrical grid emission factor was used for every facility (i.e., a Canadian average for 2018). This was done in an effort to compare emission intensity depending on the process, rather than location. As a result, the Scope 2 emission values below will not match what is being emitted at these facilities. For energy intensities, the analysis will focus on the idea of processing energy as per the previous CSPA work and the World Steel Association methodology [2]. The general idea of processing energy is to determine the amount of energy consumed to process materials from an initial state to a final state (i.e., the materials being processed are separated from the energy consumed). The energy inherent in the materials being processed is not of concern because that energy is not consumed or spent during the process. When

looking at energy inputs, only the energy sources that are consumed during the process were considered energy inputs (natural gas, electricity, etc.). The energy outputs of a process include any recoverable energy sources (often process gases, such as blast furnace gas) but not the final products nor the material that has been processed. For example, when looking at cokemaking, the coal input that is transformed into coke is not considered an input energy source because it is not consumed; it is the material that is being processed. However, when we look at a BF, the coke that is charged to act as a reductant/fuel is treated as an energy input because it is being consumed during the process. Similarly, the energy associated with the hot metal coming out of the BF is not considered an energy output because it is the main product of the BF. The analysis is done this way to allow for an understanding of the energy inputs that must be supplied at the process level to create the output of each processing step.

For the integrated steelmaking route, any energy or emissions associated with power plants/boiler houses were fully allocated to the processes within the boundaries. This will result in a slight overcount because some of the electricity/steam produced at the power plants/boilers houses will be used during the hot rolling and other finishing operations that are outside the boundary of the processes covered. However, due to the integrated nature of the processes at these facilities, it is difficult to allocate emissions to individual process steps (cokemaking, ironmaking etc.). Since all of the energy/emissions produced by the power plants/boilers houses are being considered within the boundaries, the net electricity and steam usage within the process boundaries is used. For example, if a facility produces 100 GJ of electricity and 140 GJ of steam at its cogeneration facility while consuming 80 GJ of electricity and 100 GJ of steam within the process boundaries, it would be considered that there are no electricity or steam consumptions within the boundaries (i.e., the power plant is producing more steam and electricity than is being consumed), which would result in the overcount mentioned previously. If the CHP produces the same amount of electricity and steam (100 GJ and 140 GJ, respectively) but the process boundary consumes 150 GJ of electricity and 100 GJ of steam, the net values would be taken. In this case, there would be 50 GJ of extra grid electricity consumed that would then be multiplied by the chosen grid emission factor to obtain the Scope 2 emissions. The steam again would result in a slight overcount. A summary of the energy and emission intensity by route can be seen in the following figures. As a result of the methodology pertaining to on-site electricity generation (co-generation), the Scope 2 emissions are very low for the integrated route because the fuels used to produce electricity on-site are classified as Scope 1 emissions.
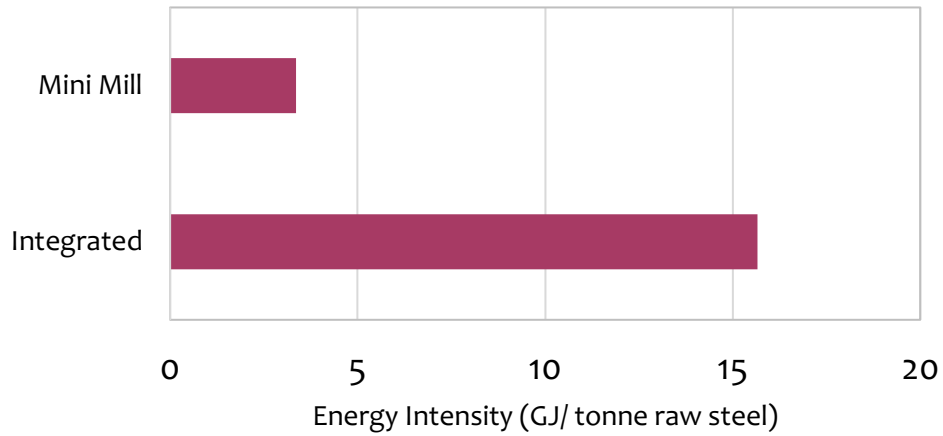
Figure 2.32. Energy intensity of Canadian steel by route (very high scrap ratio for EAF, 25% for integrated mills)

■ Scope 1   ■ Scope 2
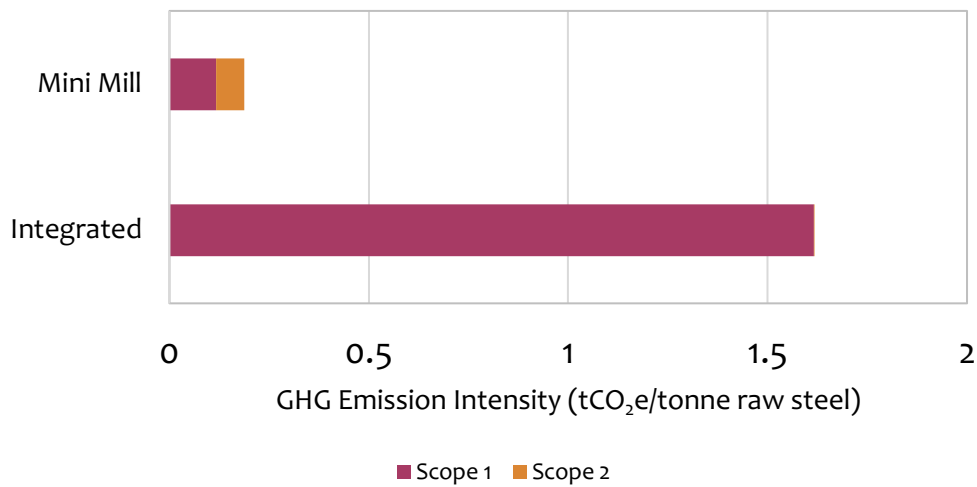
Figure 2.33. Emissions intensity of Canadian steel by route (very high scrap ratio for EAF, 25% for integrated mills)

Table 2.4. Share of emissions and share of production for BOF and EAF routes for Canadian Steel, 2018

Route	Share of Production	Share of Emissions
Integrated (BOF)	54.5%	91.15%
Mini Mill (EAF)	45.5%	8.85%

It can be seen above that due to the high scrap ratio, the mini mill route is significantly less energy and emission-intensive than the integrated route. In Canada, it produces ~45% of the steel but only contributes about 9% of the total emissions.

A recent publication called 'HOW CLEAN IS THE U.S. STEEL INDUSTRY?' provides energy and emission performance of the integrated and mini mill route in Canada specifically [42]. These figures can be seen below, where the values are normalized by imperial (short) tons of steel. Canada is in the third quartile for energy intensity for both mini mills and integrated; however, Canada has the lowest emissions intensity for the integrated route and the 2nd lowest emissions intensity for mini mills.
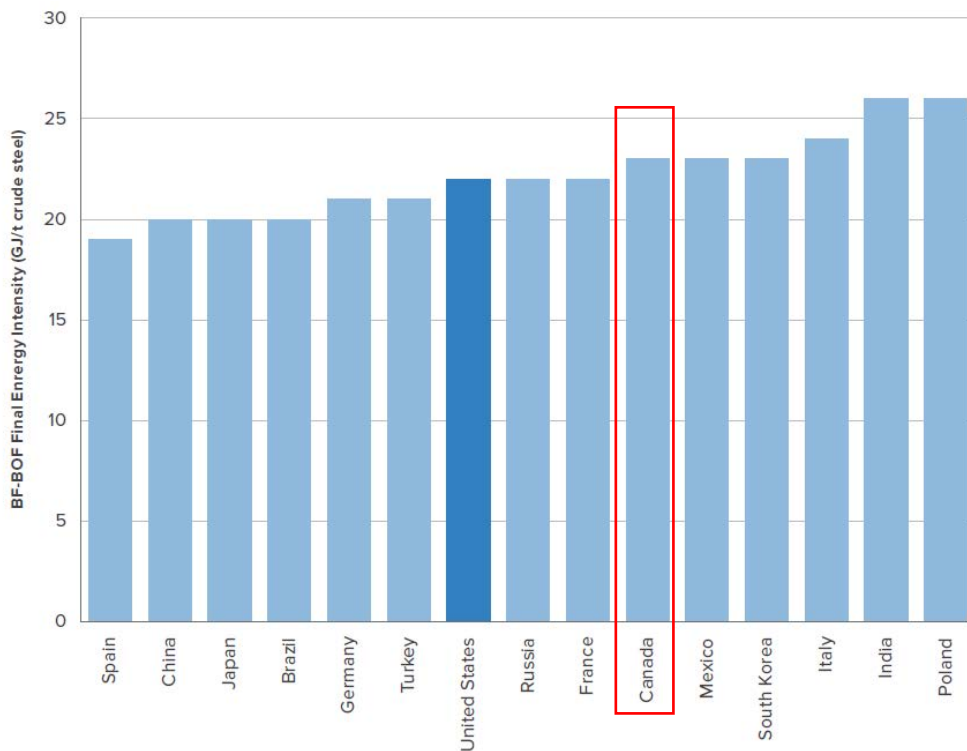
Figure 2.34. How Clean Is US Steel – integrated energy intensity [42]
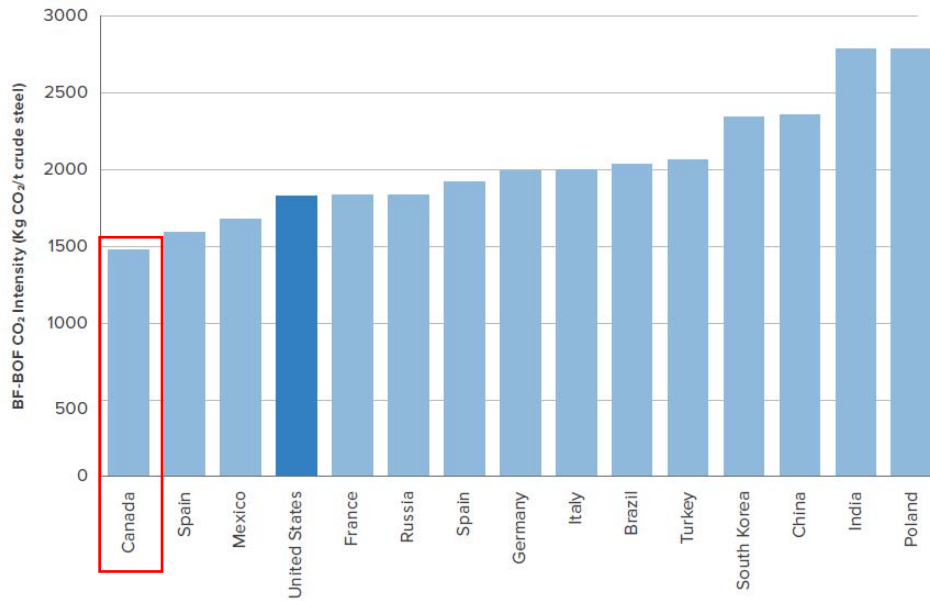
Figure 2.35. How Clean Is US Steel – integrated emission intensity [42]
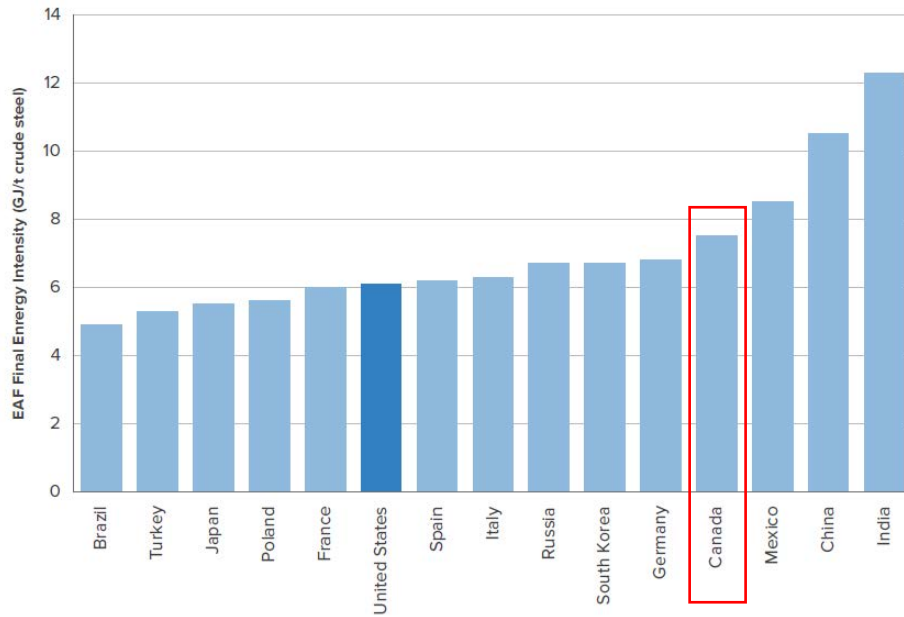
Figure 2.36. How Clean Is US Steel – mini mill energy intensity [42]
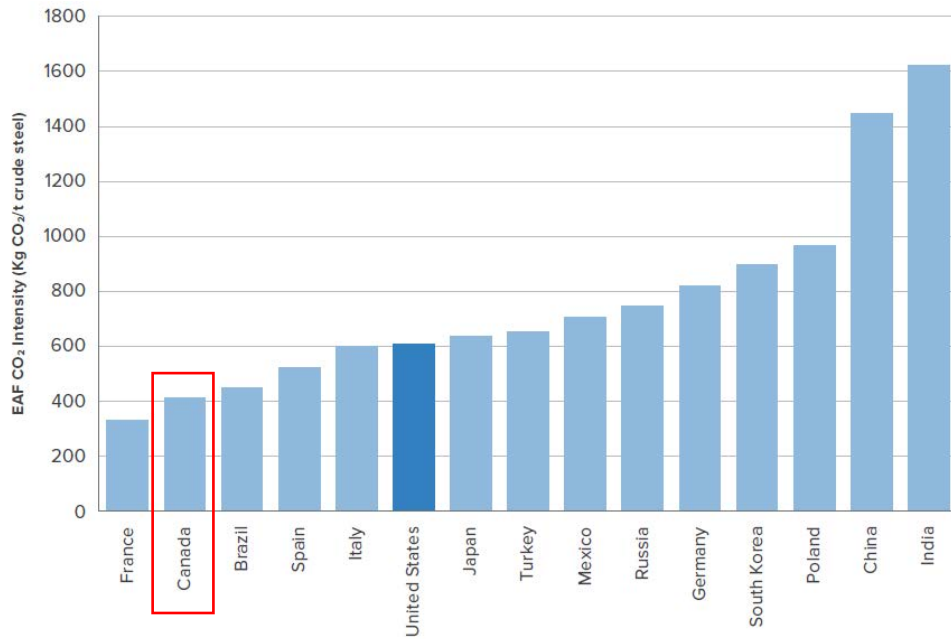
Figure 2.37. How Clean Is US Steel – mini mill emission intensity [42]

The following figures compare the energy and emission intensities values of the Canadian steel industry calculated for this report and literature values included previously that are route-specific [19,42]. 'General' refers to the non-Canadian route-specific values of **Figure 2.38** and **Figure 2.39**.
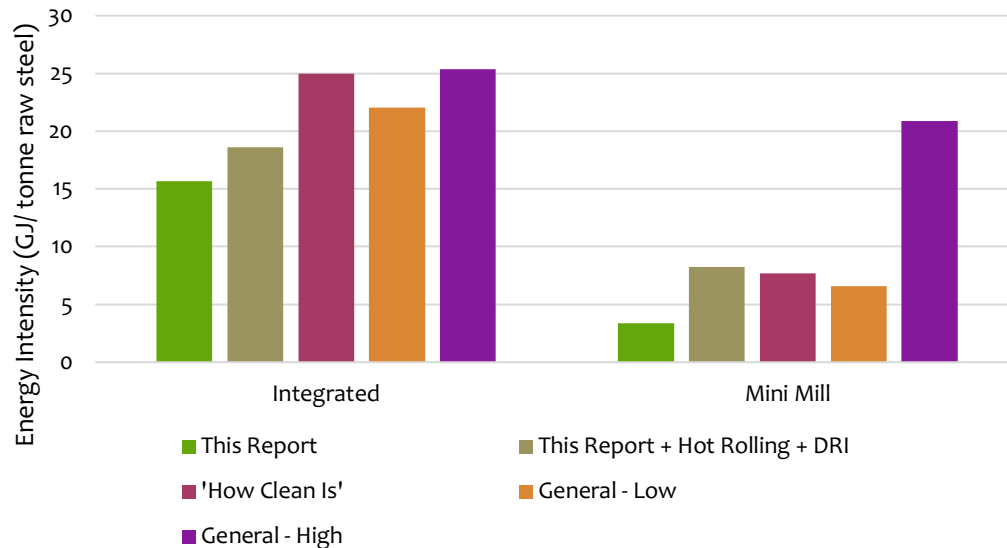
Figure 2.38. Comparison of the energy intensity for Canadian steel by production route for this report and literature values
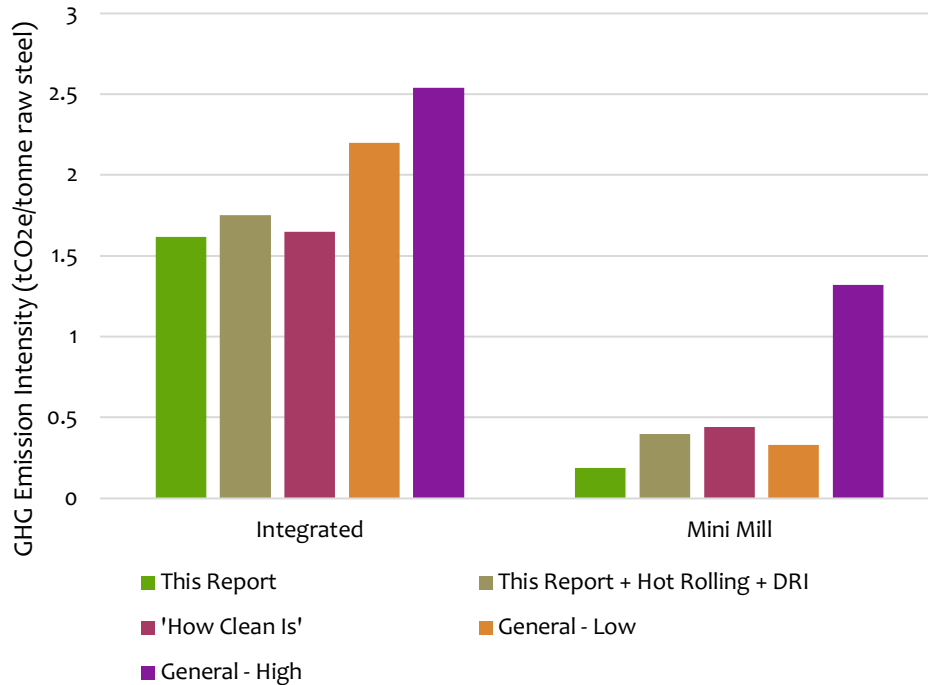
Figure 2.39. Comparison of the emissions intensity for Canadian steel by production route for this report and literature values

The first thing to note is that there is quite a wide range of energy and emission intensity values across this report and the literature reference values. This is due to the very complex steelmaking process that can utilize a wide range of feedstock materials as well as the different definitions of process boundaries.

The 'How Clean Is US Steel' report includes sintering, pelletizing, hot rolling and finishing operations in their integrated route process boundaries and therefore is expected to show larger energy use than this report. The emission values of the integrated route are primarily driven by process related emissions that largely occur within the boundaries of this report and therefore the 'How Clean Is US Steel' integrated emission values are expected to be similar to this report's values. In addition, the 'How Clean Is US Steel' report did not actually use route-specific data for the year analyzed, rather they took older route-specific energy intensities per country and scaled to recent production values [42]. As a result, these values are not expected to match exactly.

The 'General' values include an extra process (pelletizing) but other than that use largely the same process boundaries as this report. However, the emission values for the 'General' reference are not representative of Canada due to the selection of grid emission factor (0.055 tCO_2e/GJ vs 0.033 tCO_2e/GJ used for this report). The 'How Clean Is US Steel' report uses a similar electrical emissions factor of ~0.035 tCO_2e/GJ.

As a result of the different process boundary definitions, the energy and emission contribution of hot rolling and DRI were determined to better compare with the references. As can be seen when hot rolling and DRI are included, the values are very similar to 'How Clean Is US Steel' values, other than for the integrated

route's energy intensity. This reference included all the energy consumptions at the fabrication shops across Canada that do not contribute to raw steel production but rather take semifinished products and roll them into finished products. It is difficult to say if this is an error in the methodology or intended.

Regarding the differences seen for the integrated route's energy intensity, it is unclear how these references treat the energy and emissions of recovered process gases. In Canada, these gases are recovered and used within the facility as additional energy sources or reducing agents. A double count in the literature values could have occurred, depending on how the process gases are accounted for. For example, if the energy of coal input to make coke for the blast furnace and the energy of COG used as an energy input elsewhere in the facility is summed up, this would result in a double count. This is due to the COG being a by-product of coke production, and therefore the energy of the COG is contained within the energy of the coal. In addition, as mentioned previously, the 'How Clean Is US Steel" reference includes pelletizing and sintering and, therefore, would be expected to have a higher energy intensity than this report's values for the integrated route.

3 HYDROGEN AND THE DECARBONIZATION OF STEEL PRODUCTION

3.1 Review of Current Hydrogen Usage in the Steel Industry

Hydrogen has two main functions in the steel industry: to act as a reducing agent for iron oxide or as a source of thermal energy. It can perform both these functions for the integrated BF-BOF route and the mini mill DRI-EAF route, as well as being used to provide thermal energy for the final hot rolling/forming processes [43]. In this report, it is assumed that the output and quality of steel made from iron ore using either the integrated or the DRI-EAF route is equivalent. This may not be the case for all steel qualities, such as steel with very low residual levels that can only be produced through the integrated route, based on currently available technologies. Therefore, the comparisons between the two routes are a simplified approach and readers should be aware of the potential different abilities of each process.

3.1.1 What Are Reducing Agents?

In steel production, reducing agents are used to remove oxygen molecules from iron oxides to produce metallic iron either in a BF or DRI reactor. Historically, carbon monoxide has been used as the primary reducing agent. As a review, the general reduction reactions for both hydrogen and carbon monoxide are shown below. The hydrogen reaction is endothermic, and the carbon monoxide reaction is exothermic [44]. This can change the thermodynamic behaviour of the furnaces/reactors, and, as a result, there are limits to how much hydrogen can be used in a blast furnace while maintaining consistent operations.

$$Fe_2O_3(s) + 3H_2(g) \rightarrow 2Fe(s) + 3H_2O(g)$$

$$Fe_2O_3(s) + 3CO(g) \rightarrow 2Fe(s) + 3CO_2(g)$$
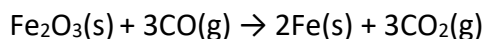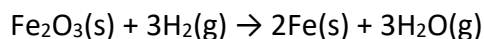
The importance from an emissions perspective is that the by-product is water vapour for hydrogen-based reduction while carbon dioxide is produced when carbon monoxide is used as the reducing agent.

3.1.2 Commonly Used Reducing Agents in Blast Furnaces and DRI Reactors

In a BF, the carbon from coke reacts with oxygen to form carbon monoxide, which then acts as the reducing agent. For DRI reactors, the reducing agent feedstock typically/historically has been natural gas or syngas from coal gasification [44]. The first stage of the DRI process is typically to process natural gas and coal into the reducing agents. This involves either coal gasification or using natural gas with SMR to produce the reducing agents carbon monoxide and hydrogen.

3.1.3 Hydrogen Usage as a Reducing Agent

Hydrogen can be injected directly into a BF as a reducing agent to partially replace coke without any major retrofits. However, there are limits to the amount of hydrogen that can be injected without significantly affecting the chemistry and operation of the blast furnace. Coke provides permeability for gas movement, and therefore there is a minimum amount of coke required in the blast furnace (260 kg of coke per tonne of hot metal) [45][18]. In addition, the endothermic nature of the hydrogen reduction reaction means that its use is limited by a decrease in the top gas temperature (minimum 118°C) and Raceway Adiabatic Flame Temperature (RAFT) (minimum 2,050°C) [45]. Therefore, the hydrogen injection rate is limited to between 19.5 to 26 kg of hydrogen per tonne of hot metal [45,46]. Reducing the amount of coke not only reduces the emissions coming out of the blast furnace, it also results in significant upstream emission reductions because less coal needs to be processed into coke.

For DRI, hydrogen and carbon monoxide are currently generated from fossil fuels to be used as reducing agents. When using a pure hydrogen stream, the initial gas reforming or coal gasification steps can be removed and replaced with a hydrogen gas preheating step [6]. This preheating step can be performed using additional hydrogen as a fuel source or using electricity, hydrocarbon fuels etc. and requires around 3,175 MJ of heat per tonne of DRI [28]. However, there are limitations to using pure hydrogen DRI. Most EAF steelmakers prefer to use DRI with 1.5-3 percent carbon because the carbon affects the melting temperature and behaviour of the DRI, and if pure hydrogen is used, there is no source of carbon [28]. In addition, the endothermic nature of the hydrogen reduction reaction necessitates additional thermal energy. Midrex, the largest DRI equipment provider, notes that these limitations can be solved using 50 m^3 of natural gas per tonne of DRI [28].

3.1.4 Hydrogen as a Fuel

Hydrogen can also be used as a fuel to produce thermal energy in the steel industry. Almost all of the heat requirements are high-grade (>500°C), with temperatures reaching up to 1350°C for reheat furnaces utilized in the rolling/forging processes [43]. As a result, any electrification of the heating sources is complex and requires a complete redesign of the equipment (i.e., high capital cost) [43]. Instead, the burners can be slightly modified to use hydrogen as a fuel, allowing for an emission-free fuel source (assuming the hydrogen is produced emissions-free) at a relatively low capital cost. Areas where thermal energy is required in the steel industry include:

- Coking ovens to process coal to coke,
- Hot stoves that provide hot air blast in the blast furnace,
- Ladle preheating,

- Preheaters for DRI,
- Alternative energy sources in an EAF,
- Reheat furnaces for shaping the steel, and
- Finishing operations utilizing burners for re-heating.

Many of these applications are unlikely to be explored as the industry moves away from coke-based iron production and towards DRI. The most obvious usage of hydrogen as a fuel in the steel industry is for the reheat furnaces because it is used regardless of which steel production route is taken. The following figure details the energy and emissions performance of a variety of burner types using methane or hydrogen as fuel [47].
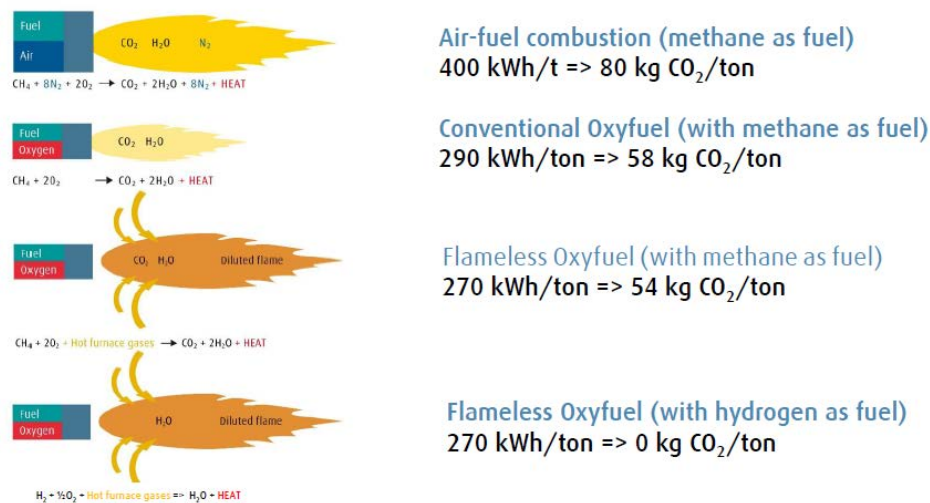
Figure 3.1. Energy and emission performance of different burners using methane or (green) hydrogen as fuel

Canadian steel facilities use natural gas and/or process gases as the heating fuel in their reheat furnaces. As a result, there could be an opportunity to significantly reduce the emissions at these facilities by using low-emission hydrogen as a fuel source for the reheat furnaces.

3.2 Previous Experience in Canada and Abroad

3.2.1 Summary of Main Hydrogen Usages to Be Analyzed

The main usages for hydrogen in the steel industry that will be analyzed in Canada for this report include:

1. Injection into a blast furnace to act as a reducing agent,
2. Injection into the DRI reactor to act as a reducing agent, and
3. Use of hydrogen as a fuel for reheat furnaces (RF)/hot rolling operations

For each usage, a literature review was performed to analyze which countries/companies are already investigating and using hydrogen for these functions. Then, for each of the three usages, an absolute

hydrogen consumption per region in Canada (Western Canada, Ontario and Quebec) as well as hydrogen intensity metrics where appropriate (hydrogen consumed in RF per tonne of raw steel, hydrogen consumed per tonne of DRI, hydrogen consumed per tonne of raw steel in DRI-EAF route etc.) were determined.

3.2.2 Hydrogen Injection in Blast Furnaces

The following section describes the current research and real-world applications of hydrogen being used as a reducing agent in the BF. There has been an extensive amount of research on this topic, including computational fluid dynamic modelling and other energy/mass balance methods. One of these references provides a summary of actual operating facilities performing hydrogen injection into a blast furnace, as seen in the figure below.

STEEL	LOCATION	ELECTROLYSER	RENEWABLE
ArcelorMittal	Bremen, Germany	Yes	Unclear
ArcelorMittal	Dunkirk, France	No	/
ArcelorMittal	Asturias, Spain	No	/
ArcelorMittal	Fos-Sur-Mer, France	Yes	Yes
Voestalpine	Linz, Austria	Yes	Yes
Thyssenkrupp	Duisburg, Germany	No	/
TATA	Ijmuiden, Netherlands	Yes	Yes
Dillinger/Saarstahl	Dillingen, Germany	No	/

Figure 3.2. Facilities reported as using hydrogen in blast furnaces [48]

However, upon further analysis, it appears most of these sites are taking process gases such as COG/BFG or Coal Bed Methane (CBD) gas, and refining/upgrading them with hydrogen gas. The resulting syngas, which contains carbon and hydrogen, is then injected into the BF. Although hydrogen acts as a reducing agent within the furnace, it is an element contained within the injected gases. However, ArcelorMittal Bremen and Thyssenkrupp Duisburg appear to be injecting pure hydrogen into a blast furnace, with trials completed and published for Thyssenkrupp [49–51]. Thyssenkrupp aimed to replace PCI with hydrogen at injection rates of 1,000 m³ per hour, which would result in emission savings of roughly 20% [51,52]. They reported a successful trial that confirmed their simulation results of hydrogen usage in blast furnaces [51].

Another example of hydrogen injection in a BF is being carried out in the Super COURSE50 project by Nippon Steel [53]. Previously, hydrogen-rich gas from within the steel mill was injected into the BF, but with the Super COURSE50 project, externally produced hydrogen will be injected into the BF. Testing of the Super COURSE50 project was anticipated to occur in 2022, with full implementation by 2050, resulting in a 50% decrease in CO_2 emissions [53].
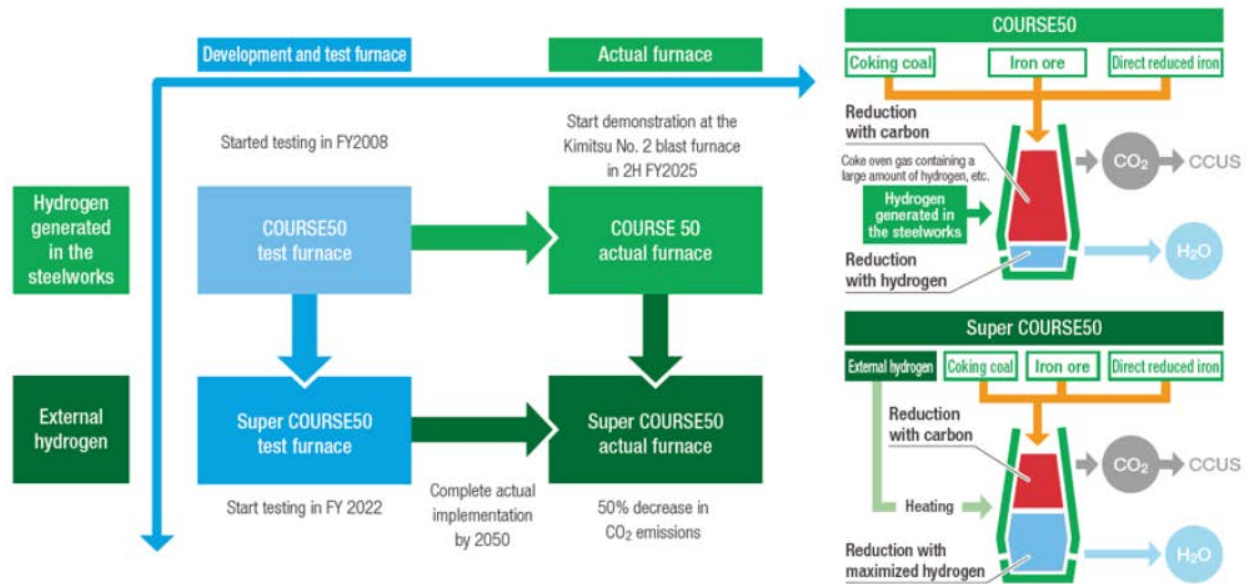
Figure 3.3. Nippon Steel's COURSE50 and Super COURSE50 projects [53]

It appears that many of these companies are transitioning directly to the DRI-EAF route and, therefore, may not complete the hydrogen injection in BF projects.

3.2.3 Hydrogen Injection in DRI Reactors

The use of hydrogen as a reducing agent in a DRI has been the main subject of focus in the steel industry's goal of decarbonization. There are dozens of examples of companies analyzing this opportunity, with full-scale implementation expected within the next five years. The most advanced projects will be discussed below, as well as the plans of the five largest global steel producers seen in the figure below.

In Canada, Algoma is investing C$700 million to convert to EAF operations using 100% scrap (i.e., no DRI), while Stelco is pursuing the support of both the Canadian and Ontario governments for their multifaceted approach to decarbonizing their business and preserving the integrated steelmaking process and the resulting high-quality, low-residual steels required by certain market segments [54,55]. There are no immediate plans for either company to operate an H2-DRI facility. It is likely that the mini mill steelmaking facilities in Canada continue using scrap instead of DRI as their feedstock, especially Gerdau, who have heavily invested in recycling steel and are focused on renewable electricity to decarbonize [56].

Being the second largest steel producer in the world, ArcelorMittal has numerous projects pertaining to hydrogen usage for DRI. ArcelorMittal Dofasco in Hamilton, Ontario, is undergoing conversion from a BF based integrated facility to a DRI to EAF facility, which will be jointly funded by the Canadian and Ontario governments (combined contribution of C$900 million) [57]. This 2.5 million tonnes-per-year DRI facility will initially operate on natural gas but can transition to hydrogen when it comes available and economically possible [57]. In Quebec, ArcelorMittal Long Products operates Canada's only DRI facility and ran in 2022 a first trial of replacing 6.8% of the natural gas used in DRI process with green hydrogen [58]. ArcelorMittal also operates Germany' only DRI facility and made a €110 million investment in a hydrogen project to test

its use instead of natural gas in DRI as well as testing how carbon-free DRI reacts in an EAF [59]. The plan is for the plant to become operational before the end of 2025, producing an annual volume of 100,000 tonnes of DRI to start. Initially, the DRI facility will be using gray hydrogen but will transition to green hydrogen. In addition, an electrolyzer pilot project will start in 2026 to supply the required green hydrogen [60].

Tonnage is expressed in million tonnes (Mt).

RANK	COMPANY	TONNAGE 2021
1	China Baowu Group (1)	119.95
2	ArcelorMittal (2)	79.26
3	Ansteel Group (3)	55.65
4	Nippon Steel Corporation (4)	49.46
5	Shagang Group	44.23
6	POSCO	42.96
7	HBIS Group	41.64
8	Jianlong Group	36.71
9	Shougang Group	35.43
10	Tata Steel Group	30.59

Figure 3.4. Top steel-producing companies in 2021 ranked by tonnage of production [61]

Hydrogen Breakthrough Ironmaking Technology or **HYBRIT** is a joint venture between SSAB, LKAB and Vattenfall that aims to replace coal with hydrogen in the steelmaking process [62]. HYBRIT aims to use green hydrogen and electricity in the DRI and EAF processes to produce emission-free steel. They have already built a pilot-scale plant that is currently operating and running trials from 2020 to 2024. In addition, they have built an underground green hydrogen storage facility that will be connected to the DRI plant with pipelines, with trials running from 2022 to 2024 [63]. A fully operational industrial-scale demonstration facility is planned to be operational by 2026 [64].

The **Salcos** project was created by German steel producer Salzgitter (one of the largest producers in Europe), and they are investigating zero-emission steel through the use of H2-DRI and EAF [65]. The Salcos project is expected to reduce emissions by 95%. In 2020, the project commissioned the world's largest high-temperature electrolysis (GrInHy2.0), built a 30 MW wind farm to power the electrolyzer and constructed a DRI plant (μDRAL) using an ENERGIRON DRI reactor that will run off of either 100% hydrogen or natural gas [66].

Tata Steel Europe, Nouryon and the port of Amsterdam have partnered to develop Europe's largest green hydrogen cluster [67]. Project components include a 100 MW electrolyzer facility (H2ermes) powered by

wind electricity to produce green hydrogen, H2-DRI using green electricity/hydrogen and green electricity EAF steelmaking. Tata Steel plan on producing hydrogen-based steel by 2030 [68].

Thyssenkrupp Steel, as part of the project **tkH2Steel**®, will be constructing a 2.5 million metric tonne DRI facility that will avoid 3.5 million metric tons of CO_2 emissions, with production expected in 2026 [69]. The project will cost over €2 billion, with the company aiming to have a leading position in the low-GHG steel market. Interestingly, it looks like they will be making DRI, liquefying it and then charging into their existing BOF, using green electricity and hydrogen as the energy source [70]. In addition, in partnership with energy company STEAG, Thyssenkrupp will be creating a 500 MW electrolyzer to produce green hydrogen [71].

Nippon Steel, the world's fourth largest steel producer, plans to start testing 100% H2-DRI in a 10-ton furnace by 2025 in their Hasaki R&D Center [53]. This project is part of the Green Innovation Fund, and Nippon expects they will require 7 million tons of hydrogen per year to become carbon neutral.

The **H2 Green Steel** project aims to build the world's first true green steel facility in Northern Sweden, with production expected by 2025 [72]. This project will utilize renewable electricity and green hydrogen to reduce GHG emissions by 95%, based on Midrex technology. The plant will be fully integrated, allowing for hot charging of materials wherever possible, using recycled steel from customers, processing slag by-products into usable materials, and using the waste heat in district heating for the surrounding communities. By 2030, this project expects to produce 5 million tons of high-quality zero-carbon steel annually [72].
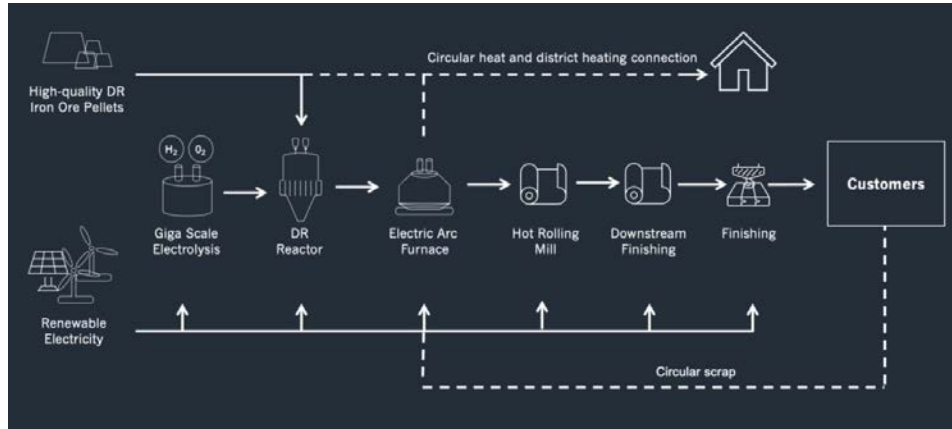
Figure 3.5. H2 Green Style Flow Chart [72]

The world's largest steel producer, China's **Baowu Group,** hired Energiron to create the world's largest hydrogen-based DRI system that can run on 100% hydrogen but also on natural gas and coke oven gas [84]. The plant is planned to be operational by 2024 and will include a carbon capture and storage system. The plant is expected to produce 1 million tonnes per year of DRI. Another Chinese Steel producer, the **Ansteel Group** (also known as Angang Group), is the world's third-largest steel producer and is developing its own fluidized-bed DRI process [73]. This plant will be operated in 2023, producing 10,000 tonnes per year of DRI. In addition, they have signed an agreement to acquire or produce hydrogen from electrolysis using wind and solar-based electricity [74]. Rounding out the top five steel producers in the world is China's

Jiangsu Shagang Group or Shagang Group. Currently, they do not have any concrete plans to use hydrogen or DRI and are instead focused on acquiring cleaner feedstock materials in collaboration with Vale [75].

3.2.4 Hydrogen as a Fuel for Reheat Furnaces

The following section describes the current research and real-world applications of hydrogen being used as a fuel in reheat furnaces/hot rolling operations. As hot rolling is required no matter which route steel is produced, this opportunity can be seen as complementary to the other two options.

Ovako Steel and Linde, a world-leader in oxyfuel steel reheating, are testing hydrogen-fueled burners for reheat furnaces [47]. They state that if pure hydrogen is to be used as a fuel (rather than mixing with natural gas), oxyfuel combustion is necessary, rather than air-fired combustion. The partnership has completed pilot tests and full-scale demonstration using 4-ton ingots. The first fossil fuel-free heated steel ingot produced using 100% hydrogen was completed at Ovako's Hofors, Sweden facility in 2020 [47].

British Steel and energy firm EDF UK are conducting a study on using hydrogen instead of natural gas for reheat furnaces [76]. This study is linked to the Tees Green Hydrogen project, which utilizes solar and wind power in the UK to produce green hydrogen through electrolysis. Currently, a study is underway with an industrial-scale demonstration to follow if the study is successful [76].

Combustion experts Danieli Centro Combustion are supplying ThyssenKrupp Steel with two primarily hydrogen-powered reheat furnaces that will be ready for operation in 2024 [77]. The initial plan is to use 48% to 66% hydrogen by volume and, therefore, they will not entirely eliminate emissions associated with reheat furnaces. However, they expect to reduce CO_2 emissions by 53 kg per tonne of steel [77].

The TWINGHY project by CELSA and a collection of steel companies/universities use a digital twin to optimize burners that run on a mix of hydrogen and natural gas [78]. They plan on testing an air and an oxyfuel burner and increasing the ratio of hydrogen over time. The project runs from 2023 to 2027, with integration into an operational industrial-scale reheating furnace demonstrator included as part of the project [78].

In 2021, Tenova launched their megawatt-sized flameless burner, TSX SmartBurner, that allows for mixtures of natural gas and hydrogen, with up to 100% hydrogen tested successfully [79]. These burners are currently commercially available and ready to install in industrial facilities.

Steel industry experts Sarralle Group are leading the H-ACERO project to develop a reheating furnace prototype that evaluates the usage of hydrogen-based combustion [80]. This prototype will allow for air-fired or oxygen burners as well as various ratios of natural gas and hydrogen fuel mixtures.

University College London (UCL) sponsored project C^4U is focused primarily on carbon capture, utilization and storage (CCUS) [81]. However, they can recover 100 Nm^3/hour of carbon-free hydrogen from steel plant process gases to be used as fuel for reheat furnaces.

3.3 Hydrogen Usage in the Canadian Steel Industry

This section will analyze the hydrogen consumption requirements of the Canadian steel sector for three opportunities: hydrogen injection in the BF as a reducing agent, hydrogen injection in a DRI reactor as a reducing agent and hydrogen as a fuel for reheat furnaces/hot rolling operations. The emission factors and Canadian facility consumption/production data were taken from previous work for CSPA [2].

3.3.1 Hydrogen Injection in Blast Furnaces

In Canada, three BFs are in operation, all located in Ontario. The focus of this section will be estimating the amount of hydrogen injection required in Canada for use as a reducing agent in blast furnaces. There are numerous constraints described below that must be adhered to when performing this calculation. These theoretical calculations may not be representative of all Canadian plants as each facility and blast furnace is unique and will require a customized approach for hydrogen injection.

As described previously, the coke within a BF provides permeability for gas movement; therefore, there is a minimum amount of coke required for the normal operation of the BF. According to the literature, the minimum amount required is 260 kg-coke/tonne of hot metal and therefore, an operation cannot go below a coke rate of 0.26 t coke per tonne of hot metal [45]. As the minimum coke rate is required for gas permeability, the coke rate only refers to the amount of coke and not other carbonaceous materials such as PCI. The theoretical hydrogen injection rate is limited to between 19.5 to 26 kg of hydrogen per tonne of hot metal [45,46]. The replacement rate of hydrogen for coke was determined to be 1.3 to 4.2 kg of coke per kg of hydrogen [6,45,46]. For all calculations, minimum, average and maximum values were calculated. For example, when calculating the hydrogen injection rate, a value of 19.5 kg H_2/tonne HM was used as the minimum, 26 kg H_2/tonne HM as the max and 22.75 kg H_2/tonne HM as the average. These values are summarized in **Table 3.1**.

Table 3.1. Variables used to calculate hydrogen injection consumption in Canadian blast furnaces

Variable	Units	Minimum	Average	Maximum
Minimum Coke Rate	Tonnes coke per tonne of hot metal		0.26	
Hydrogen Injection Rate	kg of H_2 per tonne of hot metal	19.5	22.75	26
Hydrogen Replacement Rate	kg of coke per kg of H_2	1.3	2.75	4.2

The first step is to calculate the minimum, average and maximum hydrogen injection rates by multiplying the hydrogen injection rates in the table above by the total production of hot metal (i.e., liquid iron). The average hydrogen injection rate of 22.75 kg was multiplied by the minimum, maximum and average hydrogen replacement rates in **Table 3.1** to get the range of replaced coke. The replaced coke values are then subtracted from the BFs' current coke consumption to calculate a theoretical new coke consumption with

additional hydrogen usage. The theoretical coke consumption is then divided by the hot metal production to obtain the new coke rate. The final check is to compare the new coke rate with the minimum coke rate to ensure the operations of the blast furnace are not significantly altered. The results of this analysis are summarized in the table below.

Table 3.2. Summary of theoretical hydrogen requirements for injection in Canadian blast furnaces

Variable	Units	Low Value	Average Value	High Value
Hydrogen Injection Rate	Tonnes H_2/year	121,400	142,400	159,125
Amount of Replaced Coke	Tonnes coke/year	200,000	420,000	640,000
New Coke Rate	Tonne coke/tonne HM	0.294	0.327	0.360

Interestingly, one of the facilities failed the coke permeability test at the maximum hydrogen injection and coke replacement rates and therefore the operator would need to replace some coal consumption instead of replacing coke consumption.

The emission savings from reduced coke come from a) less coal use to produce coke and b) from less coke use in the process. The direct emissions savings are easy to calculate by multiplying the amount of replaced coke by the emission factor for coke. The indirect emissions are more complicated because the emissions associated with the production of coke need to be calculated.

Other energy streams, including oxygen, steam, and compressed air, are involved in the cokemaking process. However, these are excluded because they are either produced on-site in a different process boundary and therefore included in overall emission calculations or because they are produced off-site and therefore are considered Scope 3 emissions. As can be seen, it is difficult to attribute emissions to individual processes because of how integrated all processes are. Another example of that is electricity usage. Most of the integrated facilities have power plants on site that use waste process gases and/or natural gas to produce steam and electricity for usage on-site. As a result, assigning emissions associated with electricity to each process can be quite difficult because it is not known if the electricity being used for that process is being produced on-site or taken off the regional electrical grid. For the sake of simplicity and because they are expected to be much smaller than the direct emissions savings, we will ignore the indirect emission savings.

These results are summarized in the table below. The final line of this table divides the total emission savings due to hydrogen injection in BFs by the total tonnes of raw steel produced in Canada (not just in the BF steelmaking route), allowing for the emission savings to be scaled to steel production in different years.

Table 3.3. Summary of theoretical emission savings for hydrogen injection in Canadian blast furnaces

Variable	Low Value	Average Value	High Value
Direct Emissions Savings (tCO_2e/year)	645,520	1,365,524	2,085,527
Direct Emission Savings (tCO_2e/tonne raw steel)	0.0486	0.1029	0.1571

3.3.2 Hydrogen Injection in DRI Reactor

The purpose of this section is to understand how much hydrogen would be required to support the transition of one or more integrated plants to H_2 DRI-EAF steelmaking in Canada. Not all integrated plant operators may choose this route since a diversity of production technologies in Canada will help ensure a diversity of steel qualities derived from each process, catering to markets with divergent quality and residual requirements, and addressing constraints on raw material resources for each process. All the hydrogen calculations that will be presented are a function of the scrap ratio and therefore, the hydrogen consumption can be scaled depending on jurisdictions and their requirements.

The first step is to determine how much hydrogen is required per tonne of DRI. For this analysis, hydrogen will only be used as the reducing agent in DRI. The gas preheating stage can be performed with hydrogen, green electricity, biomass or other renewable energy sources, requiring around 2,700 MJ of heat per tonne of DRI [28]. As mentioned previously, there are limitations to using pure hydrogen for DRI. Most EAF steelmakers prefer to use DRI with 1.5-3% carbon, and if pure hydrogen is used, there is no source of carbon [28]. In addition, the endothermic nature of the hydrogen reduction reaction necessitates additional thermal energy. Midrex, the largest DRI equipment manufacturer, notes that both of these limitations can be solved by using 50 m^3 of natural gas per tonne of DRI [28].

Based on CSPA data and emission factors for the only DRI facility operating in Canada, a minimum natural gas consumption in the DRI reactor required for steel carbon content and heating requirements is calculated. This value is then subtracted from the overall amount of natural gas currently being used as a reducing agent to obtain the amount of natural gas to be replaced by hydrogen. Using the volume ratio of 3:1, the equivalent amount of hydrogen was calculated. This value was then divided by the DRI production, resulting in a hydrogen consumption intensity of ~600 m^3 of hydrogen per tonne of DRI. Literature values provide a range of 550 to 800 m^3 of hydrogen. These studies often refer to using 100% hydrogen in the DRI reactor and/or using hydrogen for the preheating stage and therefore are expected to consume more hydrogen than the value determined for this report [28,53,82]. As such, this initial estimate using CSPA data agrees with literature values.

The next step is to establish a mass balance of metallic iron production in Canada to determine the amount of DRI required to meet the Canadian steel industry's production requirements. For the basis of this calculation, an average carbon content of 0.45% was used. Flat product steel will have a lower carbon

content, but the results will not be materially different. This value will be subtracted from the total raw steel production to calculate the amount of metallic iron that must be matched by DRI production.

The next step is to calculate the amount of metallic/elemental iron per tonne of DRI. First, we will look at the common characteristics of DRI as shown in the table below [72]:

Table 3.4. Common and chosen DRI characteristics

Material	Percent of Mass	Chosen Value
Metallic Iron	83% – 89%	89.1%
Iron Oxide (Fe_2O_3)	6.5% - 9%	6.5%
Carbon	0.8% - 2.5%	1.4%
Gangue (waste)	2.8% - 6%	3%
Phosphorus	0.005% - 0.09%	0%
Sulfur	0.001% - 0.03%	0%

Recall that the 50 m^3 natural gas per tonne of DRI produced a DRI with a carbon content of 1.4%. This was used as a basis to derive the chosen values for this study, as seen in the table above. The molar masses of iron and oxygen are used to calculate the percent mass of iron oxide that is pure iron, i.e., ~70%. This value will be multiplied by the assumed iron oxide content of 6.5% to determine the additional amount of pure iron contained in the iron oxide as summarized in the table below.

Table 3.5. Total metallic/elemental iron in DRI as percent of mass

Material	Percent of Mass
Metallic Iron	89.1%
Oxygen in Iron Oxide	1.95%
Iron in Iron Oxide	4.55%
Total metallic/elemental iron	**93.65%**

The following mass balance around the EAF boundary is then performed to determine the mass of DRI required to match the iron content of Canadian steel annual production.

$$Fe\ Mass_{In} = Fe\ Mass_{Out}$$

$$Fe\ Mass_{Out} = mass\ of\ iron\ in\ Canadian\ Steel$$

$$Fe\ Mass_{in} = mass\ of\ DRI * 93.65\%$$

Solving for mass of DRI

$$mass\ of\ DRI = \frac{Mass\ of\ Iron\ In\ Canadian\ Steel}{93.65\%}$$

The mass of DRI is then multiplied by the range of hydrogen consumption intensities determined previously (550 to 800 m^3 of H$_2$ per tonne DRI) to get a range of hydrogen consumption. However, the large assumption here is that all of the iron content is coming from DRI. This will not be the case for the actual operation of these facilities. These facilities will still use some amount of steel scrap because it offers a cheaper alternative than producing DRI on-site. Therefore, we need to determine the hydrogen consumption as a function of the scrap used in the EAF (which will be referred to as the scrap ratio).

The mass balance including scrap can be rewritten as below where the iron *Mass$_{in}$* now includes the iron content of scrap:

$$Fe\ Mass_{In} = Fe\ Mass_{Out}$$

$$Fe\ Mass_{in} = (1-x)*(mass\ of\ DRI*93.65\%) + x*(iron\ in\ steel\ scrap)$$

The variables *x* and *1-x* represent variable scrap ratios that will be analyzed. Scrap ratios of 0 (i.e., no scrap) all the way to 1 (no DRI) are analyzed. The steel scrap was assumed to have the same carbon content as used for steel previously (0.45%). Note that this calculation did not consider minor impurities, such as manganese, silicon, phosphorus, etc. Using this value in a mass balance, the amounts of iron covered by the various scrap ratios are calculated. These values are subtracted from the mass of iron in Canadian steel to determine the remaining amount of iron that must be covered by DRI. The DRI values are then multiplied by the hydrogen consumption intensities determined previously to determine the amount of hydrogen required as a function of the scrap ratio. The following figures show the low, average and high hydrogen consumptions as a function of the scrap ratio for Ontario, Quebec and Western Canada. At 25% scrap, currently a typical value for integrated plants, about 1,200 tonnes per day would be required at the average hydrogen consumption level for the DRI reactor, not including pre-heating or re-heating.
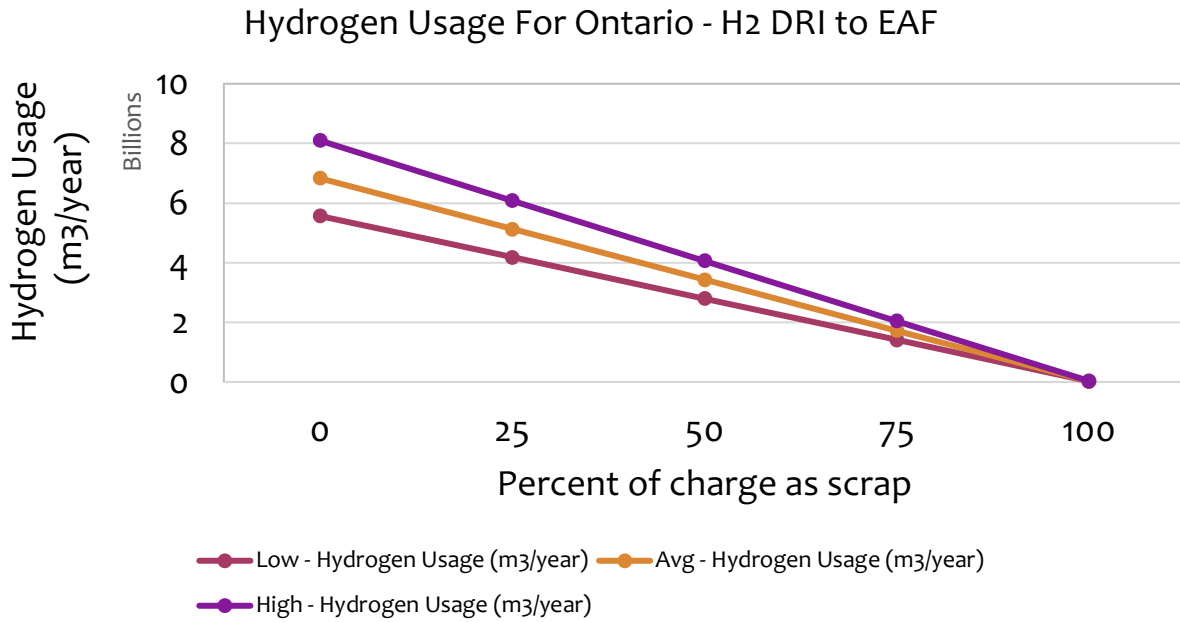
Figure 3.6. Hydrogen consumption for H2 DRI to EAF as a function of scrap ratio for Ontario
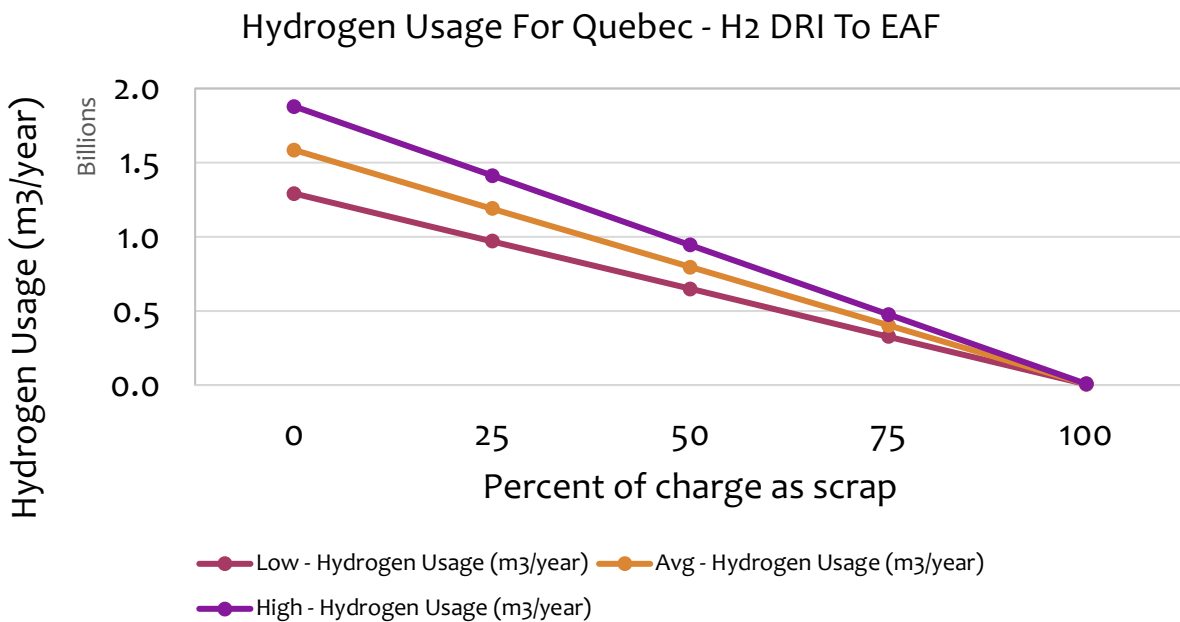
Figure 3.7. Hydrogen consumption for H2 DRI to EAF as a function of scrap ratio for Quebec
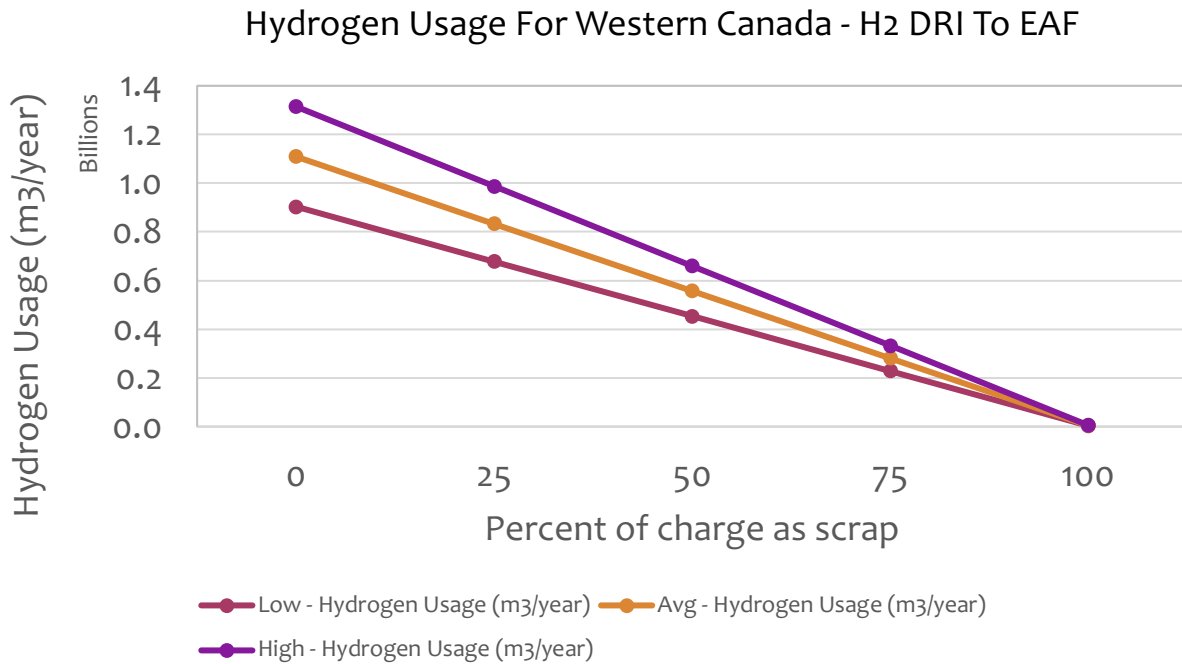
Figure 3.8. Hydrogen consumption for H2 DRI to EAF as a function of scrap ratio for Western Canada

The breakdown of hydrogen consumption per region can be seen below as well as the total hydrogen consumption requirement for all of Canada.
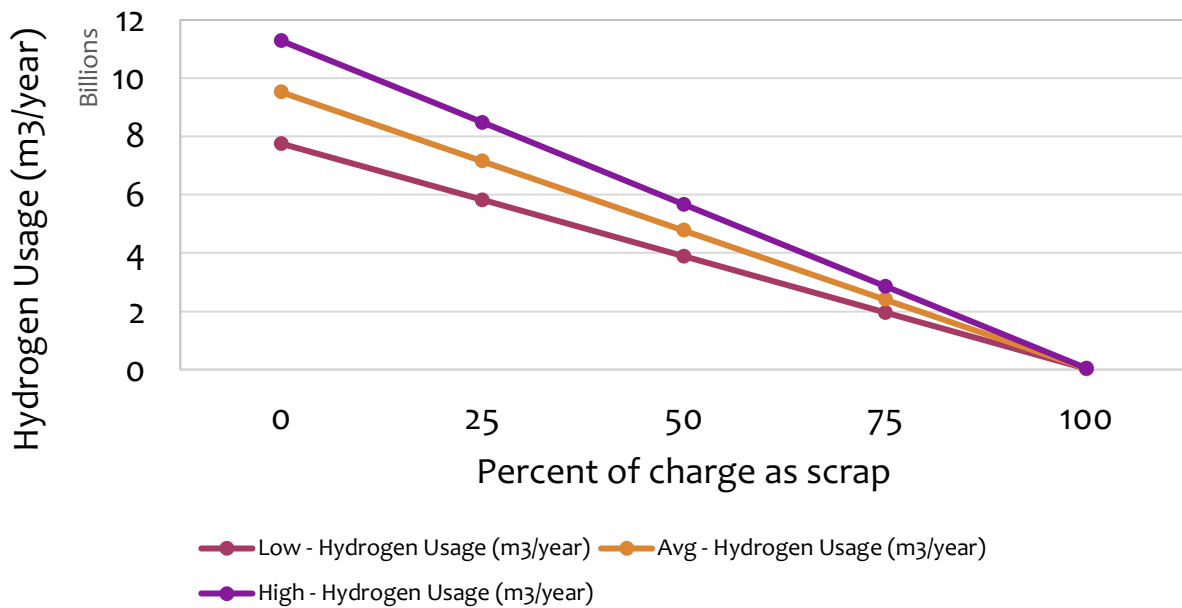
Figure 3.9. Hydrogen consumption for H2 DRI to EAF as a function scrap ratio for all of Canada

Distribution of Hydrogen Consumption by Region
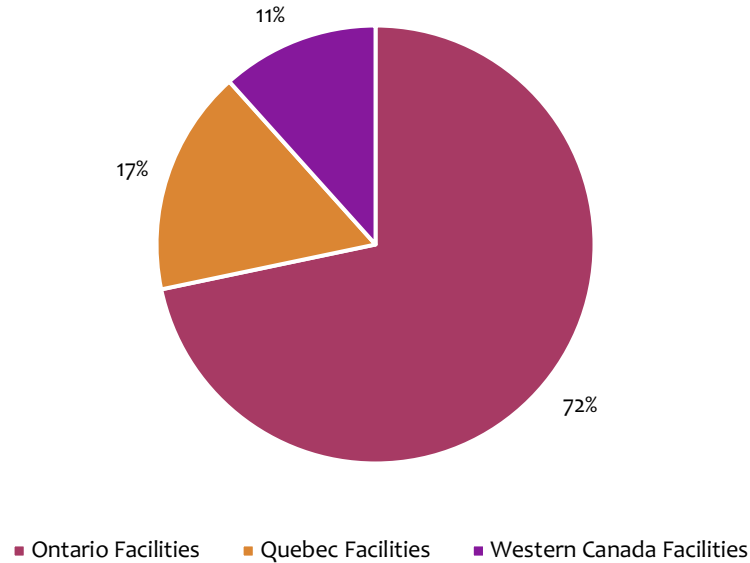
Figure 3.10. Hydrogen consumption for H2 DRI to EAF by region

Next, the hydrogen consumptions were normalized by the liquid steel output to obtain the hydrogen consumption intensities. These values will be the same for all regions but are still a function of the scrap ratio, as seen in the following figure.
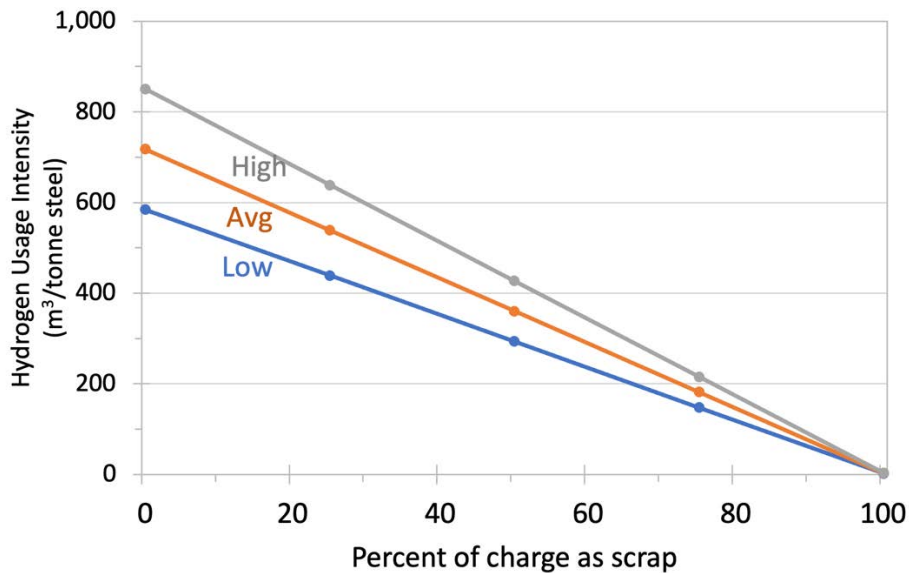
Figure 3.11. Hydrogen consumption intensity for H2-DRI to EAF route as a function of scrap ratio

These hydrogen consumption intensity metrics allow for the comparison with literature values. The values from the literature range from 600 to 800 m^3 of hydrogen per tonne of raw steel and therefore are in very

good agreement with this report's values [9,62,63]. It is very likely that these studies had different boundaries or conditions than those used for this study, such as using hydrogen for heating the DRI reduction gas heater, not including small amounts of natural gas for carbon content/heating requirements in DRI and most importantly, using 100% DRI (i.e., 0% of the charge as scrap using the figure above).

In terms of Scope 1 and 2 emissions, for the sake of this analysis, there are only two sources: natural gas usage in DRI to provide carbon content and thermal energy and then process emissions in the EAF due to the carbon content of the DRI and scrap. It is assumed that green electricity and green hydrogen (i.e., emission-free) are used and therefore do not produce any emissions. In principle, this is an idealized case to determine optimum emissions reductions for the Canadian steel industry. For jurisdictions like Quebec or Manitoba, and to a lesser extent, Ontario, the assumption of green electricity is quite valid. However, the assumption does not stand for Alberta and Saskatchewan.

Natural gas usage in the DRI process provides the carbon content of the DRI used in the EAF. To avoid a double count, the emissions due to natural gas use are assigned to the DRI process, and the process emissions due to the carbon content of DRI in the EAF are omitted as they are already captured in the natural gas emissions. The natural gas emissions will be calculated by multiplying the volume of natural gas by the appropriate natural gas emission factor. The process emissions from steel scrap are calculated by multiplying the tonnes of steel scrap (depending on scrap ratio) by the assumed carbon content of 0.45% to get the tonnes of carbon into the EAF. A mass balance of carbon is performed with the amount of carbon in the steel output (assumed to be 0.45%) subtracted from the amount of carbon in the steel scrap. This value is then multiplied by 3.664, the ratio of molar masses, to convert to CO_2 emissions. These EAF process emission values will be negative because the emissions due to the carbon content of the DRI were assigned to the DRI process boundaries and not to the EAF. However, when the sum is calculated across the entire theoretical facility, the correct values are obtained. This methodology was applied because it is simpler than trying to determine the amount of carbon in the natural gas that would be contained in the DRI and the amount of carbon contained in the DRI process gas.

It has also been assumed that biochar will be used as the slag foaming agent and therefore will not contribute to CO_2 emissions. The relatively minor amounts of N_2O and CH_4 Scope 1 emissions due to biochar usage have been ignored in this analysis. Moreover, no graphite EAF electrode consumption was considered, resulting in slightly underestimated emissions, and electricity was deemed to be carbon-free. The emission performance of this idealized H2-DRI to EAF process is shown in the figure below as a function of the scrap ratio.

Total Emissions For H2-DRI to EAF Route
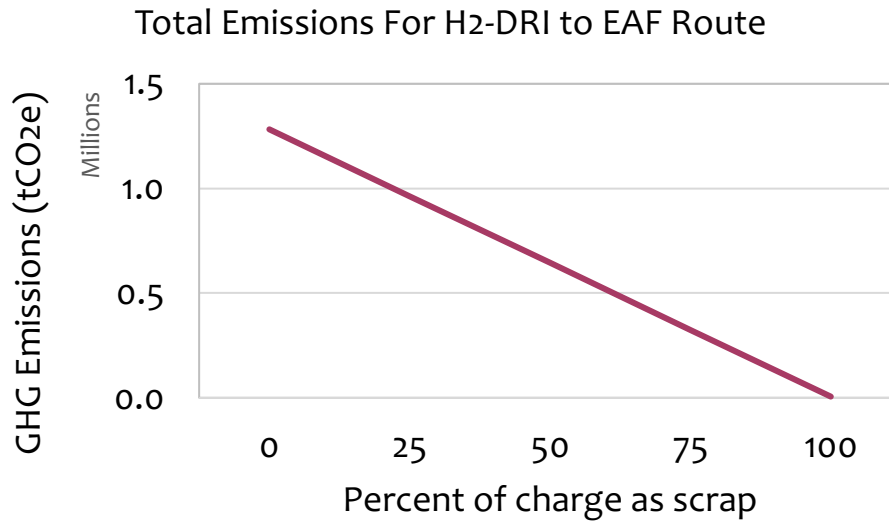
Figure 3.12. **Emission performance of the H2-DRI to EAF route as a function of the scrap ratio, with assumed zero carbon injection into the EAF and electrode graphite consumption neglected**

At 100% scrap, the H2-DRI to EAF route becomes the mini mill route. It does not reach zero GHG emissions due to the carbon content of the scrap as well as the carbon in the graphite electrodes (which have been excluded from this analysis). The carbon present in the biochar foaming agent would not be considered a Scope 1 GHG emission as it is biogenic. The emission performance as an intensity metric of this idealized H2-DRI to EAF process is shown in the figure below as a function of the scrap ratio.

Emission Intensities For H2-DRI to EAF Route
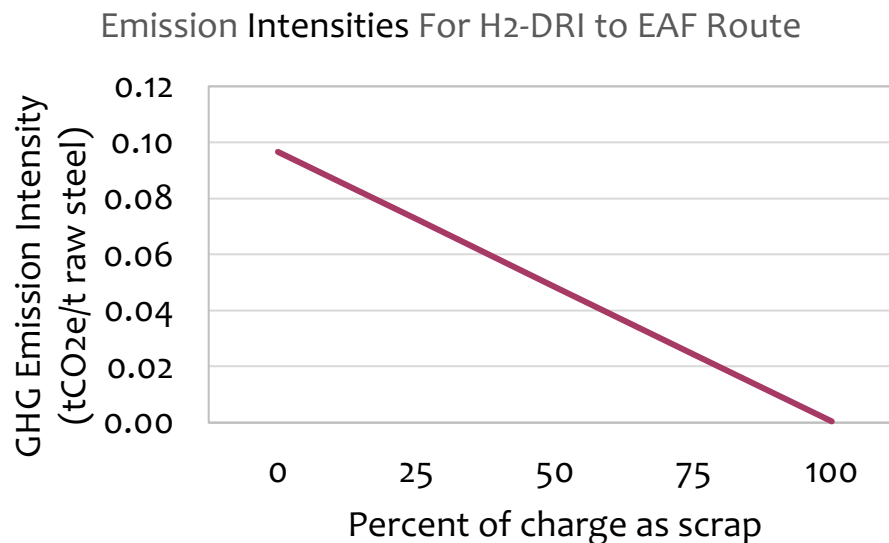
Figure 3.13. **Emission intensity performance of the H2-DRI to EAF route as a function of the scrap ratio, with assumed zero carbon injection into the EAF and electrode graphite consumption neglected**

The following figures compare the idealized emission intensity of the H2-DRI to EAF route with the current performance for the integrated and mini mill steelmaking routes. Recall that the idealized H2-DRI to EAF route uses zero emission intensity electricity while the Canadian integrated and mini mill routes use the Canadian average emission intensity. In addition, no natural gas or coal/coke is used in the EAF for the idealized H2-DRI to EAF route.
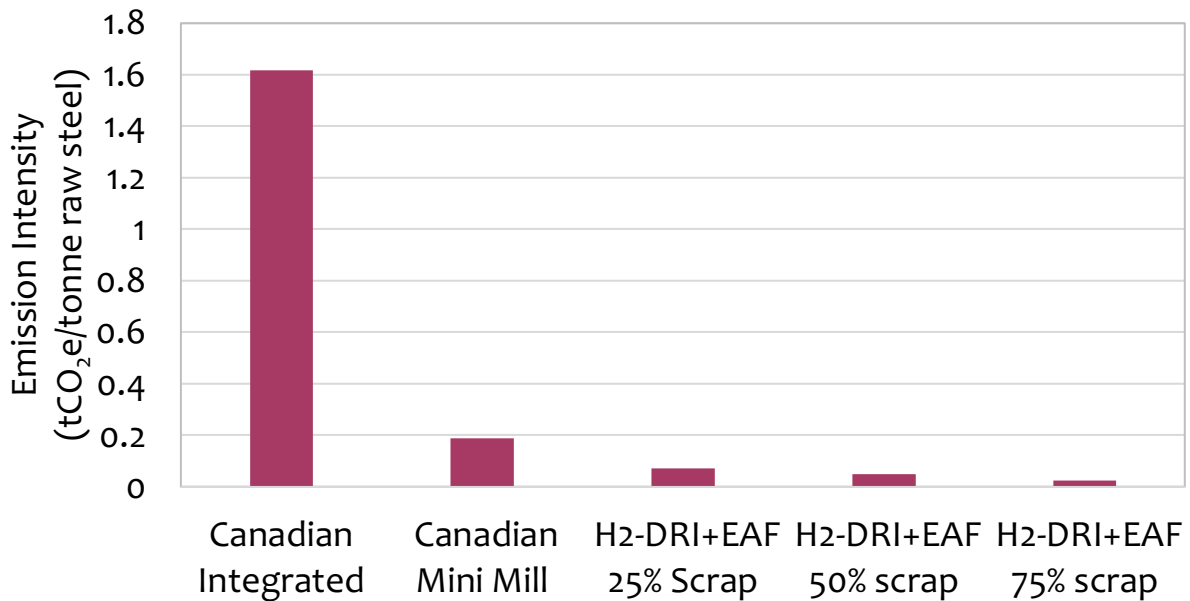
Figure 3.14. Emission intensity comparison of Canadian steel by route with idealized H2-DRI+EAF with varying scrap ratios

As expected, the more scrap that is used, the lower the emission intensity because less DRI and therefore, less natural gas is required. Alternatively, natural gas could be replaced with extra hydrogen and biochar as a carbon source to reduce GHG emissions. Even looking at the highest emission case (100% DRI), there would be a 90% reduction in emissions by utilizing H2-DRI and an EAF, as seen in the figure below (assuming the hydrogen has a zero-GHG footprint). The absolute emission savings are also plotted in the figure below (**Figure 3.5**).

Emission Decrease For H2-DRI to EAF Route
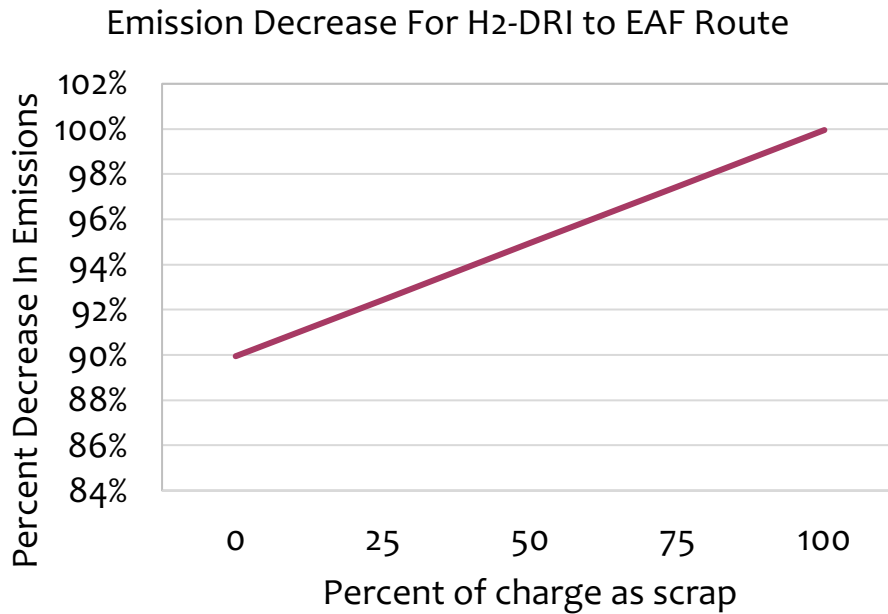
Figure 3.15. **Percent decrease in emissions by using the H2-DRI to EAF route as a function of scrap ratio**

Emission Savings For H2-DRI to EAF Route
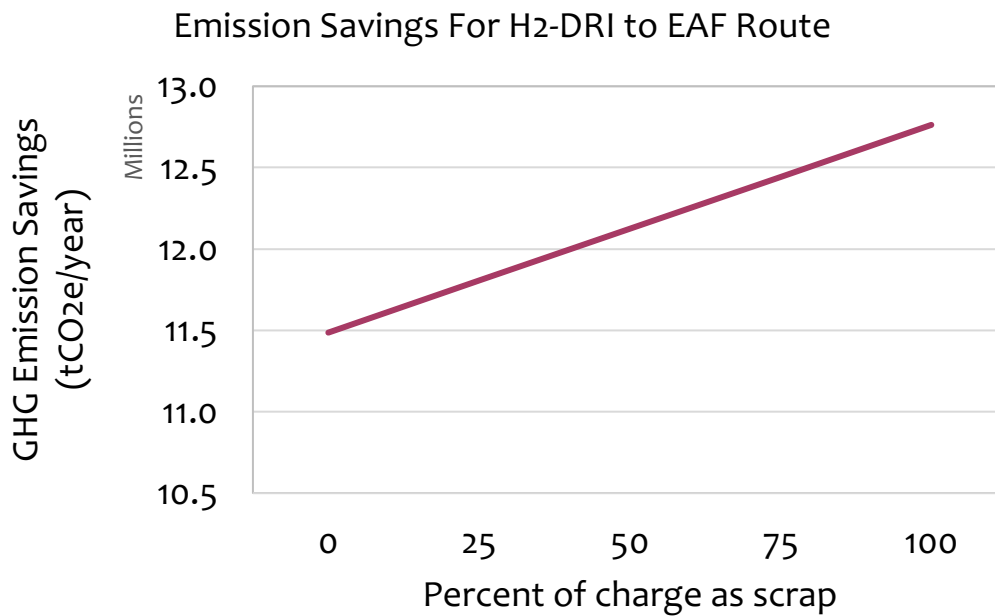
Figure 3.16. **Emission savings by using the H2-DRI to EAF route as a function of the scrap ratio**

If the intended goal is to reach net zero-emission steel production, the use of carbon capture and storage (CCS) or carbon capture, utilization, and storage (CCUS) will likely be required. CCUS is currently already in operation in the steel industry with the Al Reyadah Carbon Capture project in the United Arab Emirates, capturing 800,000 tCO_2 per year [64]. The captured CO_2 is transported via pipeline for use in nearby oil

fields for enhanced oil recovery. Pertaining to the H2-DRI to EAF route, CCS could be used to capture CO_2 from both the DRI reactor and EAF furnace, or alternative routes could be pursued, such as offsets or the additional use of biochar.

3.3.3 Hydrogen as Fuel for Reheat Furnaces & Hot Rolling

As mentioned previously, a simple and universal application of hydrogen in the steel industry could be a fuel source for reheat furnaces. The reheat furnaces are utilized regardless of which route the steel was made and often require only minor burner retrofits to use hydrogen.

All Canadian mills use natural gas as a fuel for their reheat furnaces; integrated facilities may also use process gases to supplement. These furnaces operate at high temperatures, so electrification is often impractical and would require a very large capital expense to buy/retrofit existing furnaces. Using CSPA data and emission factors, the amount of hydrogen required to run the reheat furnaces will be calculated, as well as the emission savings (assuming 'green' hydrogen use). This hydrogen usage would be in addition to the hydrogen used as a reducing agent in the DRI or BF processes.

The facility data provided does not have a split between the natural gas used in the reheat furnaces compared with natural gas used for other hot rolling processes (e.g., coiler furnace etc.). As a result, the total natural gas values will be used; however, it is very likely that hydrogen can also be used as a fuel for the other hot rolling operations, which makes this a fair assumption. The calculation methodology is as follows: the total energy of natural gas used in the hot rolling process was determined by region (Ontario, Quebec and Western Canada). Next, an equivalent amount of energy of hydrogen was calculated, which was then converted to tonnes of hydrogen per year. The emission savings were calculated by multiplying the natural gas consumption by the natural gas emission factor. The results can be seen in the table below. A hydrogen intensity value was also provided in units of kilograms of hydrogen per tonne of liquid steel to allow for scaling with different years' production.

Table 3.6. Hydrogen consumption and emission savings when used as fuel for the hot rolling process

Region	Natural Gas Savings (GJ/year)	Emission Savings (tCO₂e/year)	Hydrogen Consumption (t/year)	Hydrogen Intensity (kg per tonne steel)
Western Canada	2,900,000	160,000	22,613	14.6
Ontario	17,400,000	970,000	134,000	14.2
Quebec	2,000,000	115,000	15,913	7.2

3.4 Low-GHG Steel Premium

There has been a growing trend in the steel industry to develop mechanisms to attach a cost premium to low or zero-GHG steel. Numerous companies have branded low-GHG steel, as seen in the non-exhaustive list in the following table.

Table 3.7. Examples of a selection of steel producers with low-GHG steel branding [83–86]

Company Name	Product Name	Year Available	GHG Reduction (%)
Thyssenkrupp Steel	bluemint® Steel	2021	50 – 70
ArcelorMittal	Xcarb™ green steel	2022	N/A
Nucor Corporation	ECONIQ™ green steel	2021	100%*
U.S. Steel	verdeX® low-GHG steel	2021	75

Note that Nucor claims 100% emission-free steel by using renewable electricity to reduce Scope 2 emissions to zero, and carbon offsets are purchased to offset the Scope 1 emissions [86]. Vale offers "green briquettes", which refers to the iron feedstock rather than steel production [84]. This would result in Scope 3 emission reductions at the steel facilities themselves rather than for their clients.

ArcelorMittal's Xcarb™ green steel has been verified by an independent auditor, allowing their clients to use these low-GHG steel certificates as a way to reduce their value chain or Scope 3 emissions, in line with the GHG Protocol Corporate Accounting and Reporting Standard [83]. This presents a great opportunity for Canadian steel due to the low-emission electricity seen in many of the provinces coupled with the large volume of EAF steel production.

3.5 Overall Energy Use Comparison Between Pathways

This section compares the energy intensity by type (electricity, natural gas etc.) and steelmaking route (mini mill or integrated) for the Canadian facilities, as well as theoretical values for the H_2 DRI-EAF route and natural gas NG DRI-EAF route.

3.5.1 Deriving The H_2 DRI-EAF and NG DRI-EAF Routes Energy Intensities

Three energy intensity cases will be presented for each route, based on scrap ratios of 25%, 50% and 75%. The EAF portion of these routes uses the Canadian mini mill route data as a basis. For the H_2 DRI-EAF route, the electricity intensity is set equal to the sum of the electricity, natural gas and coal/coke intensities of the Canadian mini mills because it was assumed that all energy in the EAF will be supplied by electricity to minimize emissions. As mentioned previously, biochar will be used for the injectable carbon in the EAF and is set equal to the Canadian mini mill injectable carbon energy intensity. For the NG-DRI to EAF route, Canadian mini mill values for electricity, natural gas, coal/coke and injectable carbon were used for the EAF portion. For both routes considered, the oxygen and nitrogen intensities of the EAF portion were set directly equal to the Canadian mini mill intensities values.

For the H_2 DRI portion, the hydrogen and natural gas intensities were calculated for the low, average, and high cases as before. The electricity consumption for the H_2 DRI portion is twofold: the electricity required to power the general operation of the DRI system as well as the electrical power required to run the reduction gas heater.[2] The literature electricity value from the DRI energy balance figure (1.04 GJ/tonne of DRI) was used to calculate the general operation electricity intensity. It should be noted that this value seems quite high and the electricity requirement for the Midrex natural gas reformer, which does not operate in an H2-DRI facility, could not be separated from the overall value. However, the general operation electricity intensity is dwarfed by the EAF and reduction gas heater electricity requirements. The heat requirement for the reduction gas heater mentioned in the previous sections (~2.7 GJ of heat per tonne of DRI) was used to calculate the amount of electric heating required. These two electrical intensities were added to get the overall H2-DRI electricity requirements. The oxygen requirements for H2-DRI were taken from the DRI energy balance figure (0.082 GJ/tonne of DRI). For the NG-DRI process, the electricity, natural gas, and oxygen intensities from the literature DRI energy balance were used.

3.5.2 Energy Use Breakdown By Route Results

All of the energy intensity values in the figure below (**Figure 3.17**) are in units of gigajoules per tonne of raw steel. The total feedstock energy intensity would not be the same as the net energy intensity provided previously for the integrated steelmaking route. This is attributed to the process gases and steam being produced within the process boundaries being larger than the process gas and steam consumed within the process boundaries (i.e., all process gasses and steam are produced within the boundary, but there are process gases/steam being used on processes outside the boundary such as sintering, galvanizing, hot rolling, and other finishing operations).

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[2] The previous analysis in Chapter 3.3.2 looked at the emission performance of the H2-DRI to EAF route and assumed clean electricity, therefore the electricity requirement for the reduction gas heater would have no impact on the overall emissions. However, from an energy perspective the reduction gas heater must be included.
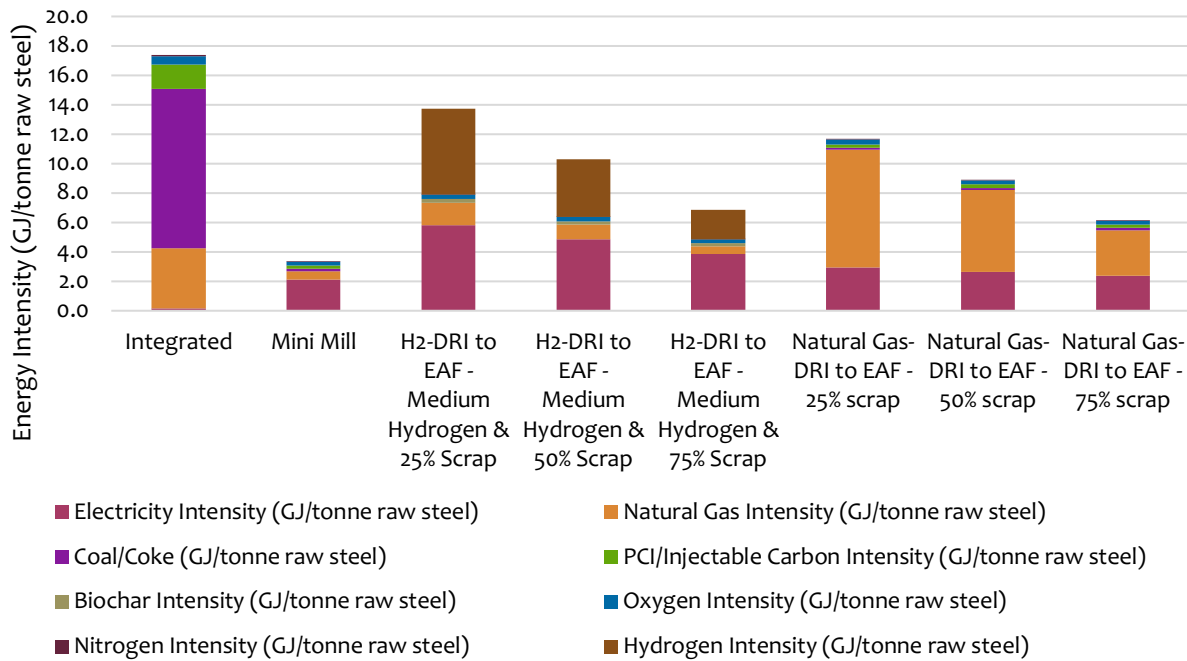
Figure 3.17. Energy Use per tonne of raw steel produced for different process routes and scrap ratios

Recall that the mini mill route boundaries only include the EAF steelmaking, ladle refining and continuous casting, with the DRI process excluded. All of these processes are included in the H2-DRI to EAF route and therefore the mini mill steelmaking route is essentially a subset of the H2-DRI to EAF route. In addition, the mini mills in Canada use a very high scrap ratio on average because only a few facilities use iron-bearing materials other than scrap (DRI, liquid iron, etc.).

The hydrogen intensity values in the figure above have already been compared to literature values in the previous section and were in good agreement. Although it is difficult to compare the electricity intensities to literature values for the H2-DRI to EAF route due to different boundary definitions, system components, energy type for reduction gas preheater, use of natural gas etc., they will be compared on an order of magnitude basis. Vogl et al. [81] and Bhaskar et al. [44] separately analyzed the requirements for H2-DRI to EAF with the inclusion of an electrolyzer and ore preheating steps. As a result, the only energy type for these cases is electricity, with hydrogen produced via the electrolyzer. Vogl determined a total specific energy consumption (SEC) of 12.53 GJ/tonne of raw steel, and Bhaskar determined an SEC of 13.40 GJ/tonne for the boundaries they defined. Vogl reported that around 2/3 of the energy is attributed to the electrolyzer, while Bhaskar provided an SEC for the electrolyzer of 9.65 GJ/tonne raw steel and 1.67 GJ/tonne raw steel for ore heating. If we remove these values from the overall SEC, we can estimate the electricity requirement for the H2-DRI + EAF route. The electricity values range from 2.2 GJ/tonne of raw steel to 4.2 GJ/tonne of raw steel and are in the same order of magnitude as this report's electricity intensity range of ~3.7 GJ/tonne of raw steel (75% scrap ratio) to ~5.7 GJ/tonne of raw steel (25% scrap). Considering the different boundary definitions and feedstock choices as well as this report using a hybrid approach with some Canadian EAF operating data, these values are relatively similar. In a third source, van Vuuren et al. analyzed the ore

heating, electrolyzer and H2-DRI portion of the route [87]. They determined 11.7 GJ/tonne DRI total with 9.3 GJ/tonne DRI for the electrolyzer. If we subtract out the electrolyzer portion, the electricity consumption would be 2.4 GJ/tonne of DRI, while this report's value for just H2-DRI would be ~3.7 GJ/tonne.

It is clear that the H2-DRI to EAF route has a lower energy intensity than the integrated route for all normal operating conditions. However, the H2-DRI to EAF route has a higher energy intensity than the mini mill route because the mini mill route is essentially a subset of the H2-DRI to EAF route (i.e., the mini mill route will always have a lower energy intensity than the H2-DRI to EAF route due to the addition DRI process). As described in Section 3.3.2, the emission performance of the H2-DRI to EAF route is significantly better than the integrated route if clean electricity and green hydrogen are used. This is attributed to the elimination of coal/coke in the process as well as a significant reduction in natural gas usage. As a result, the H2 DRI-EAF route has lower energy and emission intensities than the integrated route while providing the capability to still make high-grade steel. To date, the DRI process cannot achieve the low level of residuals in the resulting product that can be achieved using the integrated process. Pertaining to the NG-DRI to EAF route, the energy intensity is lower than the H2-DRI to EAF route, but the emission intensity would be significantly higher. This increased energy intensity of the H2-DRI to EAF route is likely attributed to the endothermic nature of the hydrogen reduction reaction in the DRI reactor requiring additional thermal energy in the form of natural gas or additional hydrogen or electric heating (CO reduction is exothermic; therefore this extra energy is not required for NG-DRI), then the fairly large electricity load for the H2-DRI route to operate the reduction gas heater and to a lesser extent, the inability to separate the Midrex natural gas reformer's electricity consumption from the overall DRI electricity consumption, which was used as the basis for H2-DRI electricity consumption calculations.

4 THE TECHNO-ECONOMICS AND ENVIRONMENTAL FOOTPRINT OF LOW-GHG HYDROGEN PRODUCTION, TRANSPORT, STORAGE AND USE IN CANADA

4.1 Introduction

Hydrogen is an important solution to decarbonize industrial energy use. Whereas electrification using low-GHG sources is often the preferred option, this is not possible or desirable for all applications. Using hydrogen in steel production can become part of an overall decarbonization strategy in Canada.

Today, hydrogen is mainly produced on-site (where needed) via the reforming of natural gas, leading to significant CO_2 emissions. This so-called 'gray' hydrogen is associated with CO_2 emissions of 9 to 10 kg_{CO2} per kg_{H2} plus an additional 1.5 to 2 kg CO_{2eq} per kg_{H2} associated with the recovery and upgrading of the natural gas [88]. Hydrogen produced today is primarily used as an industrial feedstock for the upgrading and refining of oil, generation of chemicals and fertilizers as shown in **Figure 4.1A**. In Canada, hydrogen production is estimated at 8,200 t/day (3.0 Mt/year), which has associated GHG emissions of approximately 28 Mt CO_2e/year [89].
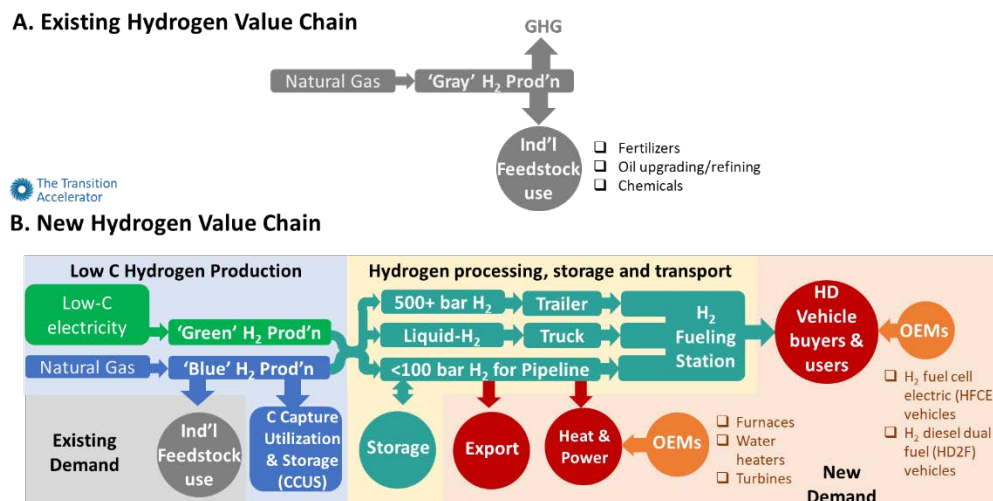
Figure 4.1. Comparison of Canada's existing hydrogen value chain (A) and a new value chain (B) based on the production of hydrogen and its use in markets for heavy-duty vehicles, heat & power, and export.
Source: Adapted from Reference [90].

To achieve the net-zero objective, low-GHG hydrogen must be made with minimal or no GHG emissions and at a competitive cost. Large hydropower resources position many provinces, such as British Columbia, Ontario, and Quebec, with a source of low-GHG electricity [91] that can be used to make 'green' hydrogen through water electrolysis. Other provinces, such as Alberta and Saskatchewan, with large fossil fuel resources and porous rocks [92] that can be used for permanent CO_2 storage can make 'blue' hydrogen via coupling natural gas reformers with carbon capture and sequestration (CCS). Low-GHG hydrogen could also be produced via new technologies such as methane pyrolysis or biomass gasification.

A net-zero energy system will see new demand for low-GHG hydrogen as a decarbonization fuel because of its flexibility, as shown in **Figure 4.1B**. Its use in hydrogen fuel cells, whether for vehicles or in stationary power applications, results in zero direct CO_2 emissions. Hydrogen can also be utilized in industrial processes, again with no GHG emissions, and used as a reducing agent. Hydrogen can be blended with natural gas for space and water heating, reducing the GHG footprint of emissions in those sectors. Renewable electricity can be used to create hydrogen through electrolysis, and through this process, hydrogen becomes an effective energy storage medium, offsetting the intermittency of wind and solar power. Aviation companies are working to develop aircraft that can be powered by hydrogen to overcome the challenges of electrification in aircraft; and the shipping industry is looking for ways to power ships using hydrogen or ammonia that is derived from hydrogen.

The use of hydrogen as an end-use fuel in domestic markets or as an energy carrier for export markets will require the creation of new value chains that connect low-GHG production to demand and make hydrogen available at a reasonable cost. The target price of hydrogen will depend on the market sector. **Figure 4.2** shows that per gigajoule of energy, Canadians pay considerably less for natural gas versus diesel or electricity. Specifically on a retail price, natural gas for heating costs C$5-16/GJ$_{NG}$, diesel for heavy-duty transport costs C$33-46/GJ$_{diesel}$ (C$1.25-1.75/L$_{diesel}$), and electricity for power costs C$17-50/GJ$_{elec}$ (C$60-180/MWh).
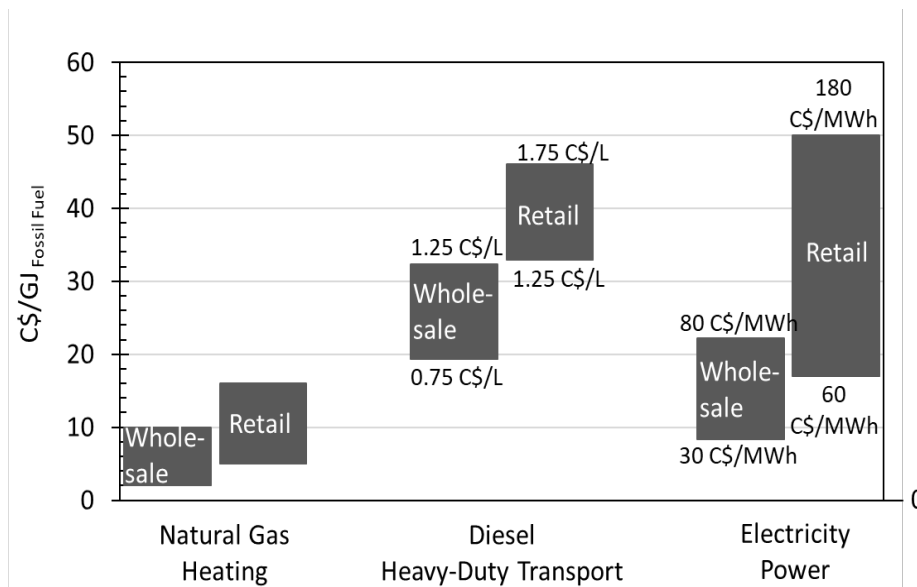
Figure 4.2. Range of wholesale and retail costs for building heating, transportation fuels and electrical power in Canada without considering carbon pricing.

Using the retail cost of energy, the relative efficiency of use of hydrogen as a fuel, and a 2030 federal carbon price of C$170/t$_{CO2}$, we have calculated the target price of hydrogen. In the building sector, the end-use distributed combustion of natural gas would add ~C$8.5/GJ$_{NG}$ due to carbon pricing. Hydrogen can be combusted without GHG emissions to provide space and water heating, like the combustion of natural gas today. In combustion, the lower heat value (LHV) of a chemical defines the useful extracted energy better than the higher heat value (HHV). Since the ratio of LHV/HHV for hydrogen (0.84) is 6% lower than the LHV/HHV for natural gas (0.90), a relative efficiency of 1.06 J$_{H2}$/J$_{NG}$ was assumed.

For the heavy-duty transport sector, the end-use combustion of diesel would add ~C$12.3 /GJ$_{diesel}$ carbon price to the retail price. The use of hydrogen fuels cell in heavy-duty vehicles would add the benefits of high-efficiency fuel cells, regenerative braking and the avoidance of idling that characterizes diesel use, which leads to a relative efficiency of about 0.86 GJ$_{H2}$/GJ$_{diesel}$ for heavy-duty transport. It is worth noting that compared to gasoline vehicles used in cities, the drive chain advantage of hydrogen fuel cell electric vehicles is much better (~0.5 GJ$_{H2}$/GJ$_{gasoline}$) but not as good as for electric vehicles (~0.25 GJ$_e$/GJ$_{gasoline}$).

For the power sector, the simplified assumption is made that electricity generation in Canada will be decarbonized by 2035, and the end use of low-GHG electricity does not lead to any GHG emissions. Therefore, the carbon price is not accounted for in calculating the target hydrogen price for the power sector. Low-GHG hydrogen is expected to be used only for peak power generation / backup power generation and for a portion of industrial or building cogeneration. A relative efficiency of 3 J$_{H2}$/J$_e$ was assumed as the efficiency to generate electricity from hydrogen (e.g., single-cycle gas turbines). **Table 4.1** summarizes the target price of hydrogen for heating, diesel use in heavy transport, and power sectors, respectively.

Table 4.1. Calculation of target price of hydrogen, based on retail cost of C-based fuels, relative efficiency of hydrogen and a federal carbon price of C$170/t$_{CO2}$.

Market Sector	Fuel	Retail cost of energy C$/GJ$_{FF}$	Carbon tax impact C$/GJ$_{FF}$	Relative Efficiency GJ$_{H2}$/GJ$_{FF}$ or GJ$_{H2}$/GJ$_e$	H$_2$ Target price C$/kg$_{H2}$
Heating	Natural gas	5-16	8.5	1.06	1.8-3.3
HD Transport	Diesel	33-46	12.3	0.86	7.4-9.6
Electricity - Power	Natural gas	17-50	--	3.0	0.8-2.4

If hydrogen must be used as a fuel, we must create new value chains to process and move hydrogen from production sites and deliver it to demand sites at the target price. Hydrogen, in its gaseous form, is much more challenging to transport and store than liquid fuels, such as gasoline or diesel, especially in small quantities. The current technologies of processing and delivering hydrogen involve either compression, liquefaction, or pipelining, depending on the distance, scale, and end-user needs. At the same time, storage technologies are critical for using hydrogen on a large scale. In the next couple of sections, we will discuss the technologies that will be used in different parts of a new hydrogen value chain spanning low-GHG hydrogen production (Section 4.2) and processing, storage, and transport (section 4.3).

4.2 Hydrogen Production

4.2.1 Blue Hydrogen: Natural Gas reforming coupled to Carbon Capture and Storage

Hydrogen is an energy carrier that can be extracted from fossil fuels, biomass, water, or a mix of these. Steam methane reforming (SMR) of natural gas has been the primary method of hydrogen production. It accounts for around 75% of the annual global hydrogen production of 70 million tons using around 205 billion cubic meters of natural gas (6% of global natural gas use), releasing over 700 $MtCO_2$ annually [93]. Major merchant hydrogen producers include companies like Air Liquide, Linde/Praxair, and Air Products. The majority of the plants produce between 100 and 200 million standard cubic feet per day (MMSCFD) of high-purity hydrogen, equivalent to between ~236 t_{H2} and 472 t_{H2} per day [94]. Typically, the limit for the largest, single-train SMR facilities is ~ 200 MMSCFD [94].

Reforming of natural gas typically releases between 9-11 kg CO_2 per kg H_2 into the atmosphere, and the hydrogen produced is typically labelled as 'gray' hydrogen. When natural gas reforming is coupled to carbon capture and utilization/storage (CCUS), the product is often called 'blue' hydrogen. In this report, we define 'blue' hydrogen as where at least 90% of the CO_2 is captured and permanently sequestered in the sub-surface.

Table 4.2. Hydrogen production plants with CCS (operating and planned).
Source: Adapted from Reference [94].

	Plant/Project name	Location	Hydrogen Production	Technology	CO_2 capture rate (%)
Operating	Air Products Port Arthur	USA	220 (200)	SMR	60
	Air Liquide Port Jerome	France	50 (45)	SMR	60
	Shell Quest	Canada	210 (191)	SMR	50
Announced/ Under Development	H-Vision	Netherlands	700 (636)	ATR	88
	HyNet	United Kingdom	100 (90)	ATR	97.2
	H21	United Kingdom	3,200 (2,900) from 9 units	ATR	94.2
	Acorn	Scotland	53 (48)	ATR	98.7
	H_2 Teesside	United Kingdom	275 (250)	TBD	98
	Air Products Alberta	Canada	>695 (>623)	ATR	95
	Air Products Louisiana	USA	>837 (>750)	ATR/Partial Oxidation	95

There are two major technologies for blue hydrogen production: steam methane reforming (SMR) with CCS and auto-thermal reforming (ATR) with CCS. **Table 4.2** summarizes the results of a literature review of operating and planned hydrogen production facilities with CCUS [94]. As can be seen, only a few hydrogen production facilities are currently operating with carbon capture, utilization, and storage (CCUS) (<90 percent capture); several others are in development (>90 percent capture).

A large-scale centralized SMR or ATR unit designed to make blue H_2 at a scale of 400 to 800 t_{H2}/day will generate 1.3 to 2.6 Mt_{CO2}/yr for CCS. This scale of CCS is required for the cost-effective sequestration of CO_2 in porous rocks at least 1 km underground [95]. Not all regions of Canada have the geology needed for CCS. However, the Western Canadian Sedimentary Basin (WCSB, which includes northern British Columbia, Alberta, and southern Saskatchewan) is an ideal location for low-cost blue H_2 production due to the supply of low-cost natural gas (**Figure 4.3**) and a geology that can safely and securely store the CO_2 by-product [95]. Furthermore, the Appalachian and Michigan basins, two of the largest sedimentary basins in eastern North America, stretch across multiple US states and reach Ontario at its southern border [96]. On the Ontario side of these basins, saline aquifers have been identified as potential carbon storage options. Saline formations represent an enormous potential for CO_2 storage, and recent project results suggest they can be used as reliable long-term storage sites [97].
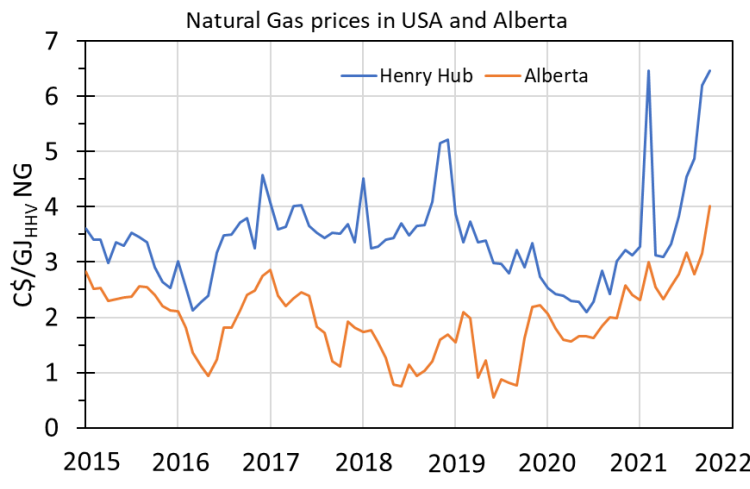
Figure 4.3. Comparative prices for natural gas (C\$/GJ$_{HHV}$ NG) in the United States (Henry Hub [98]**) and Alberta** [99] **from 2015-2021.**
Source: US\$ to C\$ conversion was done using historical data [100].

As mentioned in **Table 4.2**, Alberta has one of the biggest demonstration projects for blue hydrogen production, the Quest carbon capture and storage facility near Edmonton. In this project, CO_2 is captured from an SMR facility supplying hydrogen to the Scotford Upgrader; the captured CO_2 is then compressed and piped 65 km north to be stored 2 km underground in a saline aquifer [101]. The project has captured and stored over 5 million tonnes of CO_2 since its launch in 2015 [102].

In a recent report, the National Energy Technology Laboratory (NETL) [94] presented a detailed study on the process and techno-economic analysis for blue hydrogen production via SMR or ATR. Herein we present

a summary of the process (**Figure 4.4**) and key techno-economic parameters. For further details, the reader can refer to the NETL report [94].
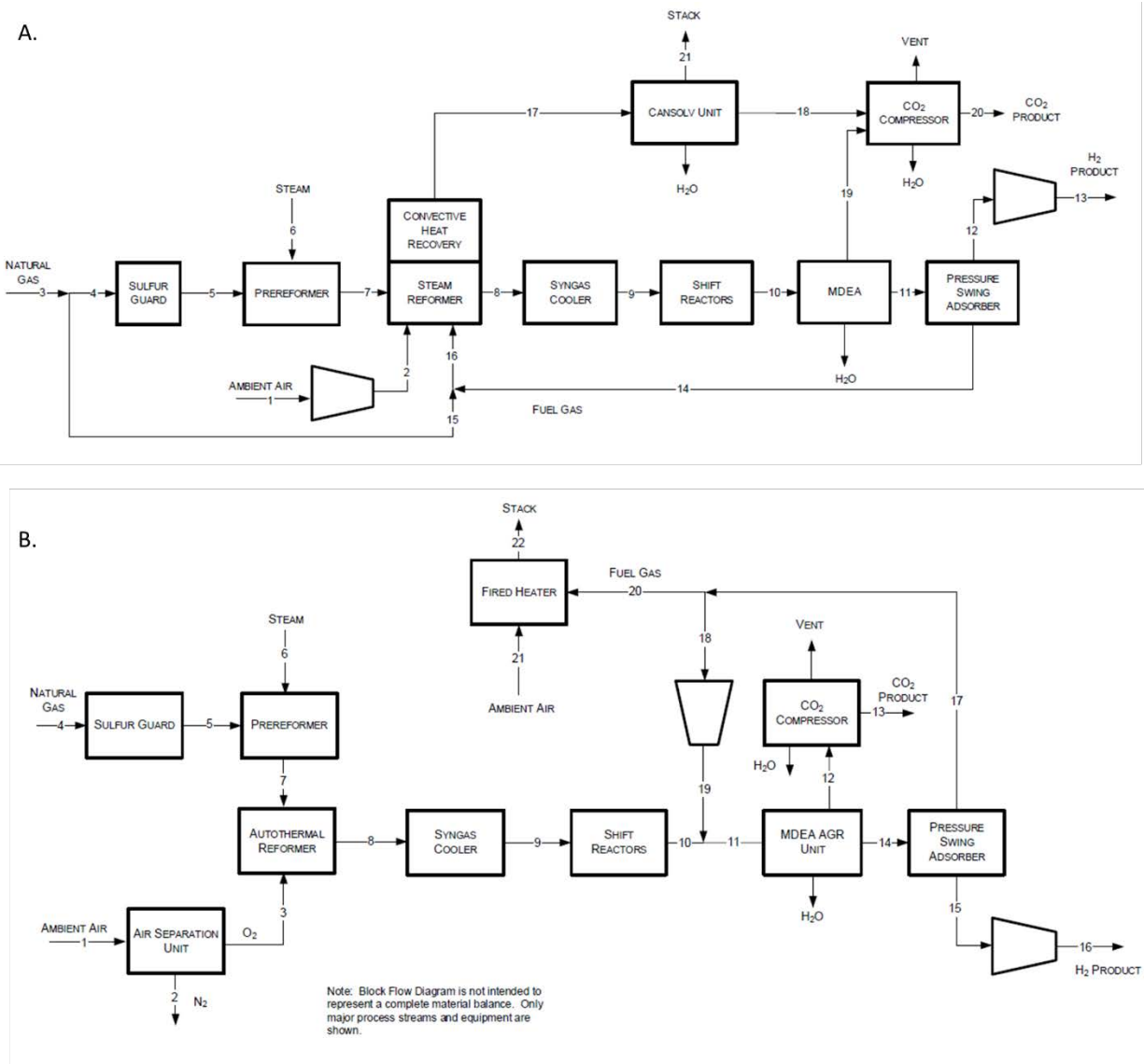
Figure 4.4. **Block Flow Diagrams of state-of-the-art (A) SMR + CCS and (B) ATR + CCS technologies for hydrogen production.**

Source: Adapted from Reference [94].

NETL modelled two plants, i.e., a standard SMR facility and an ATR facility. The plants were designed to be supplied by pipelined natural gas at a pressure of 31 bar and a temperature of 15°C. Some key components common to both plants include a sulfur polishing unit to remove the mercaptan additive using a zinc oxide sulfur guard bed. A pre-reformer is also required to reform the C2+ hydrocarbons, reducing carbon deposition on the downstream catalyst, increasing carbon capture ability, and improving product recovery.

Lastly, in both technologies, a water gas shift reactor (WGSR) is used to react the synthesis gas (CO and H_2) to form CO_2 and hydrogen-rich syngas, to maximize hydrogen yield and CO_2 separation.

In a conventional SMR process, the partially reformed gas and steam effluent from the pre-reformer is reformed in the primary reformer using a nickel-based catalyst with a conversion rate of more than 77%. The following reaction takes place:

$$[1] \; CH_4 + H_2O \leftrightarrow CO + 3H_2; \; \Delta H° = 205.8 \text{ kJ/mol}$$
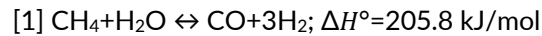
The reforming reaction is strongly endothermic, with energy supplied by firing the reformer on the outside of the catalyst tubes with recycled syngas from the downstream hydrogen purification process plus supplemental natural gas. The SMR unit also has an integrated heat recovery unit which allows for convective heat recovery from reformer flue gas. This is used to provide heat to various sections of the plant, improving plant efficiency and minimizing the need to fire natural gas. Unlike a gray hydrogen production plant, the SMR+CCS plant uses all the steam generated within the plant due to additional demands of the acid gas removal (AGR) units.

In the SMR+CCS plant, methyl diethanolamine (MDEA) technology is used for CO_2 capture. The CO_2 is removed from the syngas coming from the WGSR using a circulating lean amine. The rich amine from the absorber is sent to a stripper column, where amine is regenerated with a steam boiler. Therefore, there is a significant extra steam load in SMR+CCS plants versus only SMR plants. If the CO_2 were only captured from the shifted syngas stream, the overall CO_2 recovery would be about 62%. To increase the overall carbon recovery to >90%, a second CO_2 removal process based on the Cansolv system is utilized in the reformer heater stack to remove CO_2 resulting from fuel gas combustion. The Cansolv solvent used for post-combustion reforming configurations provides increased reactivity in the low CO_2 content reforming flue gas environment. Further details on the Cansolv system can be found in the NETL report [94].

In contrast, the ATR unit comprises a partial oxidation section and a fixed-bed catalytic reforming section. The feed gas is mixed with oxygen from the air separation unit and partially oxidized via the following reaction:

$$[2] \; CH_4 + 0.5O_2 \leftrightarrow CO + 2H_2; \; \Delta H°rxn = -36.0 \text{ kJ/mol}$$
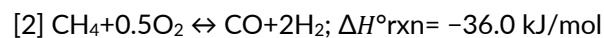
This exothermic reaction is used to generate the heat needed to drive the endothermic methane reforming reaction (see formula [1]). Unlike the SMR configuration, where reaction heat is generated outside of the catalyst tubes, the heat-generating and methane reforming reactions occur within the single autothermal reformer unit. No supplemental natural gas is required in this configuration. The methane conversion of the process is greater than 99%.

Unlike the SMR plant, the ATR configuration employs a fired heater for heat recovery. The off-gas from the pressure-swing absorption unit is combined with air and combusted in the fired heater to take advantage of the waste heat available. The hot flue gas is cooled by providing heat to various plant sections, improving plant efficiency. This section generates steam for the reforming reactions, provides feedwater preheating, and provides preheating of the natural gas feed prior to the sulfur guard and pre-reformer.

Finally, the ATR+CCS plant uses an MDEA unit like the SMR+CCS plant. In the ATR plant, there is no need for a post-combustion Cansolv system as in the SMR+CCS plant because the volumetric flow of low-pressure flue gas emitted from the plant is significantly reduced due to the absence of an externally heated reactor. This fundamental difference in technologies enables high levels of CO_2 capture exclusively through the separation of CO_2 from the high-pressure syngas.

Table 4.3. Blue hydrogen production parameters for the SMR and ATR pathways

Techno-economic Parameter	SMR + CCS	ATR + CCS
Hydrogen Purity (%)	99.9	
Hydrogen Outlet pressure (bar)	64	
Oxygen-containing species (CO_2, CO, H_2O, O_2)	< 10 ppm	
Hydrogen purification technology	PSA	
CO_2 capture rate (%)	96.2	94.5
Capacity Factor (%)	90	90
Hydrogen Production Rate (kg_{H2}/day)	483,000	660,000
Electricity Requirement (kWh_e/kg_{H2})	2.02	4.0
Natural Gas Requirement (GJ_{NG}/kg_{H2})	0.196	0.184
Effective Thermal Efficiency (%)	68.4	67.9
Raw Water Consumption (m^3/min)	8.1	11.1
Total Costs, in 2019$ (C$/$kg_{H2}$/day)	2308	1824

In **Table 4.3**, we have summarized the various techno-economic parameters around blue hydrogen production plants using SMR+CCS or ATR+CCS. Using CCS reduces the effective thermal efficiency versus an SMR plant without CCS (75%) to 68.4% and 67.9% for SMR+CCS and ATR+CCS, respectively. The ATR+CCS plant has a higher electricity requirement of ~4 kWh_e/kg_{H2} due to the carbon capture penalty and the addition of an air separation unit in the plant. It also uses more water. With respect to capital costs, the SMR plant with CCS has a total overnight cost of C$2308/$kg_{H2}$/day versus C$1824/kg_{H2}/day for ATR+CCS.

Using the parameters summarized in **Table 4.3**, a plant lifetime of 25 years, a discount rate of 8% and an electricity price of C$100/MWh, we analyzed the levelized cost of blue hydrogen (LCOH). In our analysis, we have added the costs of CO_2 transport, storage, and the carbon tax on residual CO_2 emissions to the cost of blue hydrogen [103]. The cost of CO_2 storage in a deep saline formation will vary depending on the geological formation. The CO_2 storage costs estimated using the NETL CO_2 storage cost model [103] range between C$11-26/$t_{CO2}$. The cost of CO_2 transport via a 100 km CO_2 pipeline would be ~C$2.75 C$/t_{CO2}. We have assumed the cost of CO_2 transport and storage to be C$18/$t_{CO2}$. This would add ~ C$0.05/kg_{H2} and C$0.04/$kg_{H2}$ to the cost of hydrogen produced from SMR and ATR, respectively.

The results of the techno-economic analysis suggest that the key driver of the cost of blue hydrogen production is the price of natural gas due to the high consumption at ~0.196 and 0.184 GJ_{NG} per kg of H_2 for SMR+CCS and ATR+CCS, respectively. **Figure 4.5** shows the LCOH as a function of natural gas prices. The LCOH from ATR+CCS is between C$1.58-3.05/$kg_{H2}$, which is slightly lower than the cost of production from SMR+CCS which ranges from C$1.62-3.19/$kg_{H2}$. The natural gas feedstock contributes between 40-70% of the total costs for these blue hydrogen production technologies.
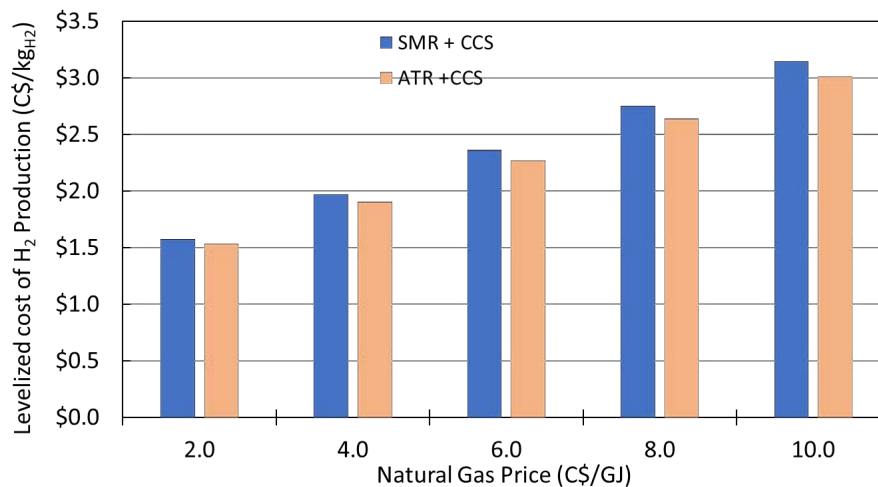
Figure 4.5. Levelized cost of blue hydrogen production as a function of natural gas prices.

Source: Techno-economic parameters adapted from Reference [94].

With improvements in the large-scale deployment of CCS, large-scale blue hydrogen plants could potentially produce hydrogen at <C$1.5/$kg_{H2}$ in places with low-cost natural gas. Even if the natural gas price increases to C$10/$GJ_{NG}$, the cost of blue H_2 production would still be ≤C$3/$kg_{H2}$, which would be significantly lower than the cost of green hydrogen in most places worldwide, as discussed in the next section.

4.2.2 Green Hydrogen: Water electrolysis

Water electrolysis is an electrochemical process that splits water into hydrogen and oxygen. Less than 0.1% of global hydrogen production comes from water electrolysis today [93], and the hydrogen produced this way is mostly used in markets where high-purity hydrogen is required (for example, electronics and polysilicon). With declining costs for low-GHG renewable electricity from solar PV and wind, interest in electrolytic hydrogen is growing, and there have been several demonstration projects in recent years.

Today, the two main electrolyzer technologies that exist commercially are alkaline electrolysis and proton exchange membrane (PEM) systems. Alkaline electrolysis is a mature and commercial technology used since the 1920s for hydrogen production in the fertilizer and chlorine industries [93]. Several alkaline electrolyzers with a capacity of up to 165 MW were built in the last century, although almost all of them were decommissioned when SMR for hydrogen production took off in the 1970s. Alkaline electrolyzers are characterized by lower capital costs compared to PEM systems due to the avoidance of precious metal catalysts [104,105]. While alkaline electrolysis systems operate at high system efficiencies (~55–70%, lower heating value, LHV), low current density (<0.45 A/cm^2) and low operating pressures (<30 bar) negatively impact system size and hydrogen production costs [106]. Also, dynamic operation (frequent start-ups and varying power input) is limited (25–100% of nominal load) for alkaline electrolyzers and can negatively affect system efficiency and gas purity [107].

On the other hand, PEM water electrolysis was pioneered by Grubb in the early fifties, and General Electric Co. led development in the 1960s to overcome the drawbacks of alkaline electrolysis [93]. The PEM systems run on pure water as an electrolyte solution, and so avoid the recovery and recycling of the corrosive potassium hydroxide electrolyte necessary in alkaline electrolyzers. Today, industries are inclined towards the PEM system due to its compact design, high system efficiency (52–69%, LHV) at high current density (1–2 A/cm^2), fast response, dynamic operation (0–160% of the nominal load), low temperatures (20–80°C) and the ability to produce ultrapure hydrogen at elevated pressure (30–80 bar) [105,107,108]. PEM has drastically reduced electrolyzer stack costs over the last few years and is expected to be the dominant technology for sustainable hydrogen production by 2030 [93,105].

A large-scale PEM electrolysis plant consists of the electrolyzer stacks and the mechanical and electrical balance of plant (BoP) components [109,110] as shown in **Figure 4.7**. The electrical BoP consists of the AC to DC rectifier for converting grid electricity. In contrast, the mechanical BoP consists of other auxiliary components such as pumps, heat exchangers, the temperature swing adsorption (TSA) subsystem and most importantly, a deionizer (DI) system.

PEM electrolyzer system
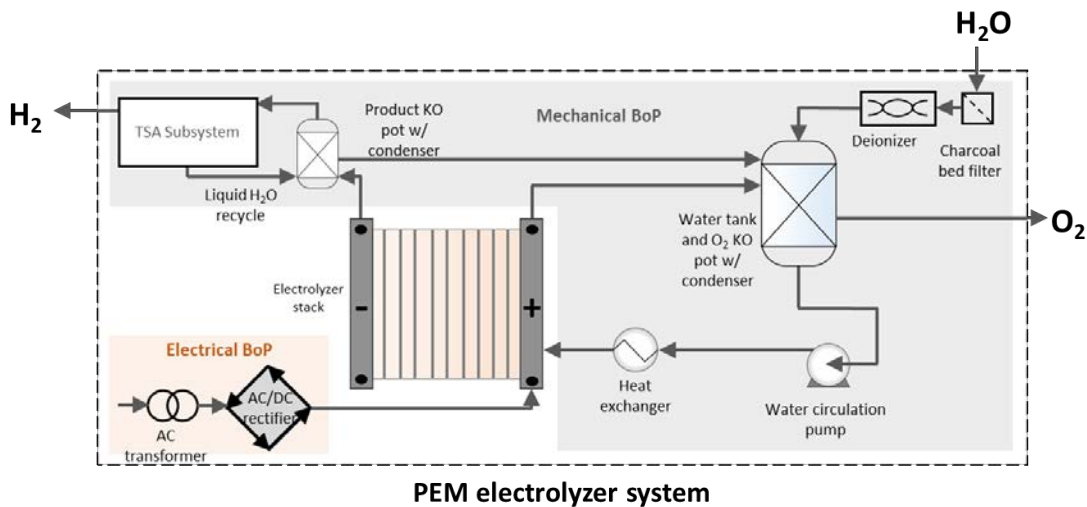
Figure 4.6. Schematic of PEM electrolyzer system. Adapted from Reference [109]**.**

The production costs of hydrogen from water electrolysis are determined by various technical and economic factors, including the capital cost (CAPEX) of the electrolyzer, its conversion efficiency (kWh/kg$_{H2}$), electricity costs and annual operating hours [111,112]. **Table 4.4** summarizes the techno-economic parameters for a PEM electrolysis system [109,111]. The electrolyzer stack is responsible for 60% of the CAPEX costs of PEM electrolyzers. The power electronics, gas-conditioning, pumps, and plant components account for the rest. The future cost projections will be influenced by innovations for the technologies themselves. Experts estimate that R&D investments that lead to developing low-cost electrodes and membranes, system-level optimization, and economies of scale in manufacturing will lead to significant CAPEX reductions for PEM electrolyzers. These have been summarized as future techno-economic parameters in **Table 4.4**.

Table 4.4. Model parameters for PEM electrolyzer costs.

Source: References [109,111].

Parameter	Units	Current (2020)	Future (2040)
Electrolyzer CAPEX	C$/kWe	1622	719
Efficiency (LHV)	%	61	70
Annual O&M	% of CAPEX	2	2
Stack replacement cost	% of CAPEX	15	15
Stack lifetime (years)	years	7	10
Plant lifetime (years)	years	20	20

Assuming an 8% return on capital cost investment and a 20-year plant lifetime, the levelized cost of hydrogen (LCOH) today and by 2040 was calculated as a function of the electricity price and annual operating hours as shown in **Figure 4.7**. We include all costs such as capital costs (CAPEX), operation costs (OPEX), fixed O&M as well as stack replacement costs in our cost assessment.

In addition, it is important to discuss the requirement and cost of high-purity water. PEM electrolysis plants typically need ~10 kg of water to produce 1 kg of hydrogen. In our recently published study [110], we calculated the energy and costs to purify water using a double-pass reverse osmosis (RO) unit as required by the PEM electrolyzer. Combining carbon filters and pre-treatment steps provided a wide spectrum of purification. The results indicated that energy (0.03 kWh per kg H_2) and costs for water purification (C$0.04 per kg H_2) are relatively minor (< 1%) in comparison to PEM water electrolysis. This is a direct result of the energy-intensive water electrolysis process, with ~55 kWh energy (including balance of plant) needed to electrolyze 10 kg water versus only 0.03 kWh to desalinate and purify the same amount of water. Therefore, water purification costs are not incorporated into the analysis presented here.
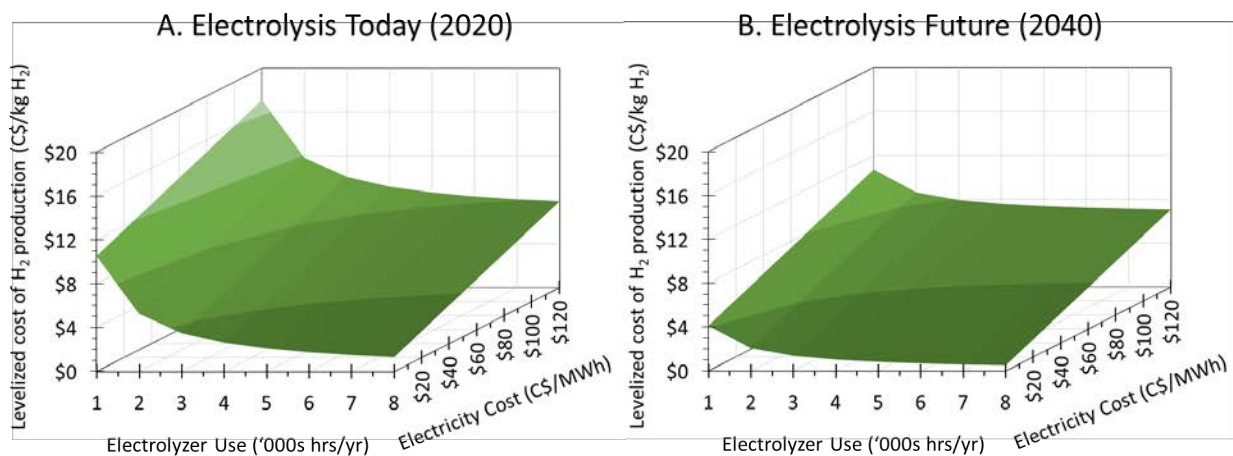
Figure 4.7. The effect of electricity cost (C$/MWh) and annual operating hours (hrs/year) on the cost of green H_2 production for a PEM Electrolyser today (A), and in 2040 (B) when the market is mature.

The results for the current cost of production indicate that the key cost determinant is the price of electricity. For example, an increase in the electricity price from C$20 to C$100/MWh can increase the LCOH 2-3 times, irrespective of the electrolyzer CAPEX. Furthermore, there is a significant impact of annual operating hours on the LCOH, which are in turn determined by the capacity factor of the power source.

In today's scenario, there is a significant challenge for low-cost green hydrogen production. For example, producing green hydrogen at <C$3/$kg_{H2}$ will require near-continuous access (6000+ hrs/year) to low-cost (<C$30/MWh), low-GHG electricity. Large hydro-powered provinces such as British Columbia and Quebec have reported the availability of excess or surplus low-GHG electricity [91]. In Ontario, some power is exported at very low pricing, and some surplus electricity is sometimes available and could then be converted to hydrogen. Since electricity is expensive to store, this excess electricity could be used to make green hydrogen through water electrolysis. However, this excess electricity is only available for limited amounts of time and not continuously as required by water electrolysis, making hydrogen storage necessary to provide continuous supplies. Also, with strongly increased power demand in the future, these surplus amounts may no longer be available. Provinces like Alberta currently do not have low-GHG grid power available to produce green hydrogen. In such provinces, dedicated renewable power such as that from centralized wind farms could be used for electrolysis. However, the low-capacity factor (34%) and current costs of wind electricity (C$40/MWh) in the province will make it challenging to make low-cost green hydrogen [113,114]. It must be noted that a key advantage of green hydrogen is that it can be produced on or near the demand site, eliminating the cost of hydrogen transport. Therefore, the feasibility of using green versus blue hydrogen should consider the cost of blue hydrogen processing and delivery.

The techno-economic results also indicate that by 2040, the lower CAPEX of PEM electrolyzers will make it possible to use dedicated low-capacity factor (25-40%) renewable power to produce green hydrogen at a competitive cost. Specifically, with the decline in PEM electrolyzer costs, green hydrogen could be produced at <C$3/$kg_{H2}$, with electricity prices below C$50/MWh, available for 3000+ hours/year. This would allow flexibility to produce green hydrogen at competitive prices across the country.

The techno-economic results presented above assume that the oxygen by-product is vented to the atmosphere. In the transition to a net-zero future, oxygen by-product management could be a key aspect of both the economic feasibility and environmental impact of water electrolysis. The use of oxygen in various industrial processes could be used to generate high-concentration CO_2 flue gas suitable for CCS. Water electrolysis produces 8 kg of high-purity (> 99.99 %) oxygen for every kg of hydrogen. Thus, the sale and use of this high-purity oxygen could lower the levelized cost of hydrogen production from water electrolysis, even though only slightly. Of particular interest is the use of oxygen in oxy-combustion turbine cycles, in which a pure or enriched oxygen stream is used instead of air for combustion [115]. Also, the use of this pure oxygen in ATRs eliminates the need for air separation units, which could be beneficial. The combustion of fossil fuels in nearly pure oxygen, rather than air, presents an opportunity to simplify and lower the cost of CO_2 capture and sequestration [115]. If by-product oxygen from electrolysis can be used, it can

significantly help drive the economic feasibility of the process and help decarbonize Canada's energy systems.

It is important to note that water electrolysis can only produce 'green' hydrogen if low-GHG electricity is available. **Figure 4.8** shows the carbon intensity of green hydrogen based on the current carbon footprint of grid electricity across various provinces of Canada [91]. The results suggest that various provinces such as Nova Scotia, Saskatchewan, Alberta, and New Brunswick are not well placed to produce hydrogen via electrolysis using the current grid. However, with the Government of Canada's aspiration to decarbonize the country's electricity grid by 2035, Canada may be able to make low-GHG green hydrogen in any province.
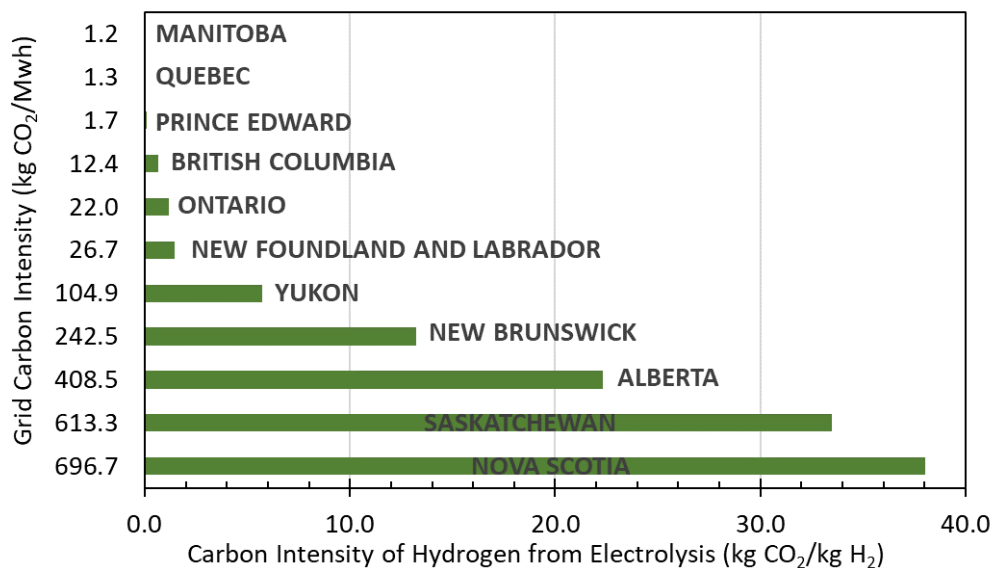
Figure 4.8. Summary of CO$_2$ emissions (kg$_{CO2}$ per kg$_{H2}$) for water electrolysis process based on the current grid carbon intensity (kg$_{CO2}$/MWh) for electricity generation in various jurisdictions.
Source: Grid Carbon Intensity calculated using Reference [91].

4.2.3 Turquoise Hydrogen: Methane Pyrolysis

Methane pyrolysis is a technology still under development for hydrogen production but could have far-reaching implications. This process decomposes methane into hydrogen and solid carbon ($CH_4 \rightarrow C + 2H_2$). The carbon is not oxidized, so no CO_2 is emitted. Solid carbon can be disposed of or alternatively, can be used as a raw material (e.g., as carbon black), leading to short- or long-term contributions to CO_2 emissions. Depending on the required hydrogen purity and conversion rate, such processes might operate without additional gas cleaning or upgrading. If only hydrogen without carbon is the desired product, the theoretical efficiency of the process is 59% [116,117]. The remaining energy contained originally within the natural gas is stored as carbon.

If cost-effective, these 'methane pyrolysis' technologies to produce "turquoise hydrogen" could be deployed anywhere there is natural gas supply, even if there is no potential for carbon capture and storage. This could rapidly expand the availability of fuel hydrogen for transportation, building or heat and power markets by piggybacking on existing natural gas infrastructure. The technology is attractive for provinces such as Alberta, blessed with low-cost natural gas. In a recently published study [116], Timmerberg and coworkers analyzed the costs and GHG emissions for methane pyrolysis technologies. In the next couple of paragraphs, we have summarized these results.
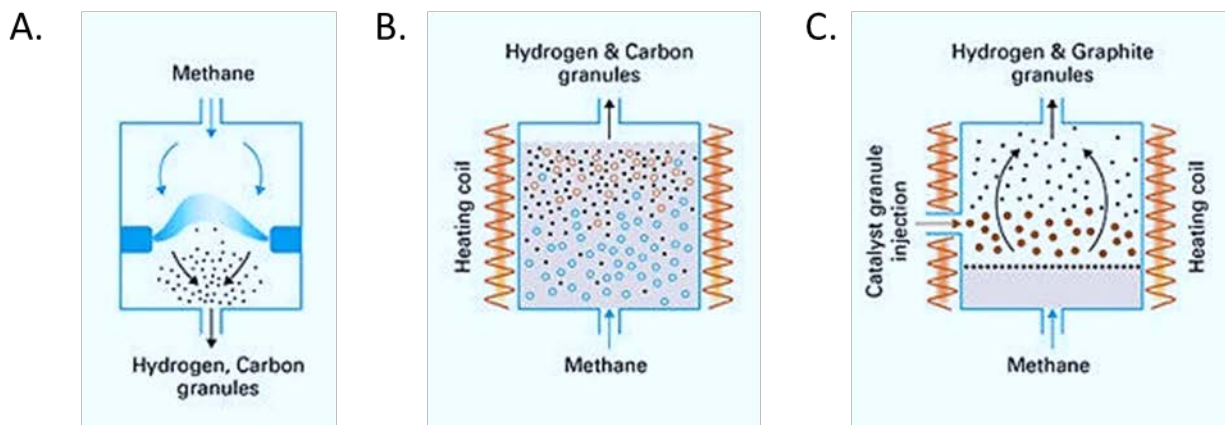
Figure 4.9. Methane pyrolysis technologies: (a) Plasma Reactor Systems, (b) Molten Metal systems and (c) Conventional Gas Reactor Systems.
Source: Adapted from Reference [118].

The three main process technologies, as shown in **Figure 4.9** for methane pyrolysis and discussed in the Timmerberg study [116] are namely:

1) Plasma Reactor Systems: Plasma is an ionized state of the gas containing free charge carriers. Most plasma processes operate without a catalyst and can likely be powered by renewable electricity. The two different plasma technologies are:

   a. Thermal plasma-based systems: A hot plasma homogenously heats up the process gas, leading to its decomposition and typically shows higher conversion versus cold plasma processes.

   b. Non-thermal or 'cold' plasma systems: In a cold plasma, the electrons show a much higher temperature than the heavier species, such as neutrons and electrons. The electrons can have temperatures of several 10,000°K, whereas the complete gas is much colder. Cold plasma processes have lower conversion rates but higher selectivity versus hot plasma processes.

   Several plasma processes for methane decomposition have been developed in recent years. The most prominent examples are the Kvaerner process and the process of Monolith Materials [119], both using a hot plasma generated through graphite coils targeting carbon black production.

2) Molten Metal Reactor Systems: Molten metal reactors rely on a liquid metal at high temperature to decompose methane gas and allow carbon black to rise to the surface of the metal. Various metals such as tin, lead, copper, and iron have been tested. The energy required to heat the metal can be supplied

from natural gas, hydrogen, or a reactor design that allows for electric heating. Recently, a company called Arenius developed a pilot-scale molten metal reactor system for methane pyrolysis.

3) <u>Conventional Gas Reactor Systems</u>: Conventional gas reactors with and without catalysts have been assessed for methane pyrolysis. However, catalytic processes have a challenge with separating the carbon deposited on the catalyst surface. Universal Oil Products developed the Hypro process [120] using a fluidized-bed reactor with a Ni catalyst at 1,150 K, followed by a catalyst regeneration with air, i.e., only hydrogen and not carbon was produced.

Table 4.5 summarizes the techno-economic parameters and costs for the three different methane pyrolysis technologies. A weighted average cost of capital of 5% was assumed, and a plant lifetime of 30 years.

Table 4.5. Techno-economic parameters and costs of different methane pyrolysis configurations. From [116], costs were converted from Euros to Canadian dollars at a conversion rate of 1 Euro = C$1.4.

Technology	Investment costs (C$/ (kg/h H_2))	Electricity consumption (kWh/kg H_2)	Methane consumption (MJ/kg H_2)	Annual O&M (% of invest.)	LCOH (C$/kg$_{H_2}$)
Thermal plasma reactor powered by electricity	49,554-155,868	11.7-17.8	222.1-223.5	3.9-18.6%	2.8-6.5
Molten metal reactor (Catalytic)	32,458	0.0	252.6	5%	2.2
Conventional gas reactor without catalyst	15,742-50,241	0.0	155.6-306.3	2%	2.2-2.6

It is important to note that there is a lot of uncertainty around the design, costs, and energy requirements of methane pyrolysis technologies. Therefore, the cost of turquoise hydrogen production could vary significantly from the numbers summarized in **Table 4.5**.

On the other hand, methane pyrolysis yields 3 tonnes of solid carbon as a by-product for every tonne of hydrogen produced. The kind and quality of the obtained carbon strongly depend on the process characteristics, reaction conditions, and the catalyst applied [121]. The formation of carbon nanotubes and carbon nanofibers generally occurs over metal catalysts. In carbon-catalyzed reactions, carbon deposits with different morphologies have been obtained. If this carbon is a marketable product, it can significantly impact the costs and GHG emissions of hydrogen production. Prices for carbon products range from C$550 to C$2,800 per tonne for carbon black itself, and significantly higher prices of >C$1,000,000 per tonne can be achieved for high-grade special carbon products [116].

Carbon black shows the greatest global demand for these various carbon products. The market size of carbon black today is ca. 16.4 Mt/year, and over 90% of the global carbon black produced is used in tires, rubber products and other plastics [122]. If carbon black were to be produced via methane pyrolysis, it would correspond to a hydrogen production of 5.5 Mt/year, which is ~7% of global hydrogen demand [116]. Clearly, if a few large methane pyrolysis plants were implemented industrially, the current market would not

be able to absorb the large amounts of carbon produced. However, it seems possible that low-cost carbon from methane decomposition systems could find new applications, such as in construction materials, heavy industry, or soil amendment. At the same time, it would be important to analyze emerging applications of high-grade special carbon products as described above.

Lastly, carbon credits and returns through the marketing of carbon black could be considered. Currently, carbon black is mostly produced from heavy crude oil fractions processed in the furnace black and oil-furnace process. This process also yields hydrogen typically used for providing heat for the process as well as externally. The production leads to GHG emissions of 2.62 kg $CO_{2eq.}$/kg of carbon black [116]. These production-related GHG emissions could be avoided if carbon black from methane decomposition were used instead.

Currently, there is much interest in the development and commercialization of novel technologies for the production of hydrogen from natural gas using a conversion technology where the byproduct is carbon black (elemental carbon) rather than gaseous CO_2. Companies working on methane pyrolysis include:

- Monolith (https://monolith-corp.com/methane-pyrolysis)
- Hazer (https://hazer.wpmudev.host/about/#hazerprocess)
- Ekona Power (https://www.ekonapower.com/)
- Aurora Hydrogen (https://aurorahydrogen.com/)
- New Wave Hydrogen (https://www.newwaveh2.com/)
- BASF (https://www.basf.com/ca/en/who-we-are/sustainability/we-produce-safely-and-efficiently/energy-and-climate-protection/carbon-management/interview-methane-pyrolysis.html)
- Modern Electron (https://modernelectron.com/)

4.2.4 Other Technologies

Rapid industrialization, urbanization and increasing population have led to continuously increasing waste generation. Municipal solid waste (MSW) refers to recyclables and compostable materials, as well as garbage from households, businesses, institutions, and construction and demolition sites. Kaza et al. [123] reported the amount of municipal solid waste (MSW) generated globally in 2016 as 2.01 billion tonnes, and it is projected to increase up to 2.59 and 3.40 billion tonnes by 2030 and 2050, respectively. Converting MSW to hydrogen is an opportunity to reduce waste and produce a zero-emission fuel.

In Canada, the responsibility for managing and reducing waste is shared among federal, provincial, territorial, and municipal governments. Municipal governments manage the collection, recycling, composting, and disposal of household waste, while provincial and territorial authorities establish waste reduction policies and programs, approve, and monitor waste management facilities and operations. In Canada, we generated approximate 34 million tonnes of MSW 2016 [124]. Of this amount, 9 million tonnes (27%) were diverted through material recovery facilities or centralized organics processing operations (i.e., recycling and composting), and 25 million tonnes (73%) were sent for disposal in landfills, to incineration facilities, for thermal treatment (e.g., energy from waste, gasification) or residual waste processing (e.g., conversion to an

alternative fuel source) [124]. Canada's MSW contains 47% organic matter such as table scraps, leaf and yard waste, disposable diapers and sanitary products, pet feces, screenings from sewage treatment plants, 12% paper and wood and 13% plastics [124].

A.

B.
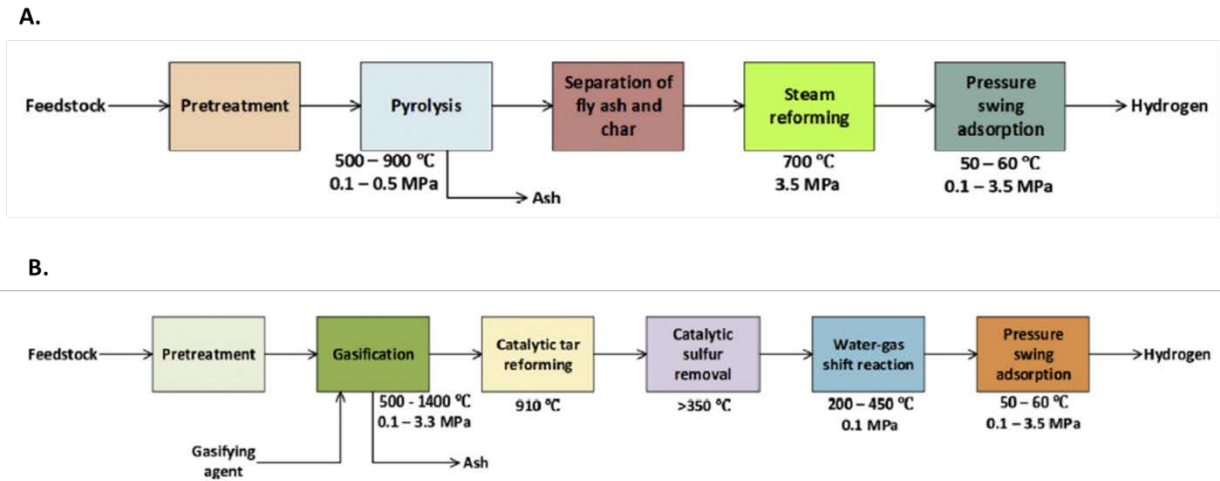
Figure 4.10. Schematic representation of (A) pyrolysis and (B) gasification technologies to produce hydrogen.

Source: Adapted from Reference [125].

Various technologies are being developed for converting MSW to hydrogen include gasification, pyrolysis, dark fermentation, photo fermentation, and microbial electrolysis. Pyrolysis is a thermochemical technology that occurs in the absence of oxygen at a pressure of 0.1-0.5 MPa and temperatures between 350 and 900°C (**Figure 4.10A**), where feedstock is transformed into biochar, pyrolysis oil, and a gas stream containing H_2, CO, CH_4, CO_2, and additional gases [125]. After separating the char, steam reforming can be used to convert the CH_4 in the product gas to syngas. The syngas may then be steam-reformed or subjected to the WGSR to increase hydrogen yields, which is then separated via pressure swing adsorption (PSA). Pyrolysis is commonly used to produce charcoal and fuel gases from wood, coke, and heavy petroleum fractions, but it is not very successful with MSW as a feedstock because MSW is a highly heterogeneous feedstock [126]. It is also challenging to control oxygen levels during pyrolysis as waste traps oxygen.

Gasification is also a thermochemical process that occurs in a low oxygen environment between 500 and 1400°C [125], in which carbon-based feedstock is converted primarily to syngas (**Figure 4.10B**). Air, steam, oxygen, and stem-oxygen are the common gasifying agents, and the main chemical reactions occurring in the gasifier are:

$$C + H_2O \rightarrow CO + H_2$$

$$C_xH_y + xH_2O \rightarrow xCO + (x + y/2)\ H_2$$
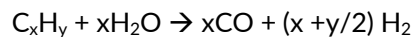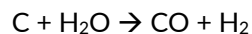
The hydrogen content can then be increased via a water gas shift reaction (WGSR), and finally, the CO_2 can be removed via PSA. However, prior to WGSR, it is necessary to remove tar and sulfur from the syngas. The

Hydrogen and the Decarbonization of Steel Production in Canada

feedstock composition affects hydrogen yield and gasification efficiency, and depending on the feedstock, the process needs to be optimized.

MSW gasification technology has been researched, piloted, and is already commercialized. Enerkem Alberta Biofuels and Sierra's FastOx Pathfinder in California are two examples of existing commercial, operational gasification plants that convert (fractions of) MSW into syngas, which is converted to renewable diesel, ethanol, fertilizer, and other renewable chemicals [126]. Hydrogen production from MSW gasification has been developed by Japan Blue Energy Co., and is being piloted by Ways2H, to process waste and extract hydrogen for transportation fuel or for electricity [126]. Toshiba also uses its advancements in hydrogen energy in Kawasaki, Japan, in an innovative 'Hydrogen Hotel' where hydrogen from waste plastics supplies 30% of the hotel's energy needs. Since both gasification and pyrolysis require significant energy, it is imperative that these processes be powered by low-GHG energy and coupled to carbon capture and storage.

In their recent report, the National Energy Technology Laboratory (NETL) [94], presented a techno-economic analysis for coal/biomass gasification with CO_2 capture for hydrogen production. The process was based on an oxygen-blown, entrained-flow gasifier similar to the Shell gasifier. The feedstock consists of coal and 30 percent by weight of biomass, including chicken litter, sewage sludge, and milled wood, which was co-fed into the system with coal at a total gasifier feed rate of 1,400 t/day. Shell gasifiers are capable of utilizing a wide variety of coal types, and compared to slurry-fed gasifiers, the dry-fed, cooled-refractory lined Shell gasifier has a lower O_2 requirement and produces a gas with a higher H_2S/Carbonyl sulfide ratio, which improves sulfur recovery. The solvent technology for CO_2 capture was a two-stage Selexol process. For further details, the reader can refer to the NETL report [94].

Figure 4.11 shows the LCOH from the gasification plant at a coal price of C$60/t and biomass/waste price of C$110/t (negative costs for waste use were not considered and may change these results). The largest contributor to the gasification cases is the capital cost, accounting for 54% of the LCOH due to the greater complexity of the gasification plants versus reforming plants.

Levelized Cost of H_2 production via co-gasification ~5.1 C$/kg$_{H2}$

■ CAPEX ■ Fixed OPEX ■ Variable OPEX ■ Fuel ■ CO2 transport and storage
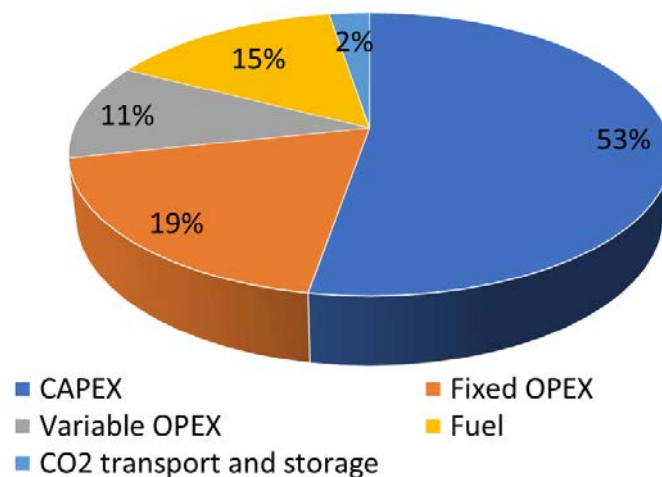
Figure 4.11. Levelized cost of hydrogen production via coal/biomass co-gasification.
Source: Adapted from Reference [94].

The fuel cost portion of the LCOH (C$0.78/kg$_{H2}$) in the coal/biomass co-gasification plant is about double that of the coal-only plants due to the higher cost of biomass than coal. The study results demonstrated that biomass/waste gasification, coupled with CO_2 capture and sequestration, can produce hydrogen at competitive costs for distributed production and play a role in certain market sectors. However, the large-scale adoption of the technology will depend on significant development of technology and lowering of capital costs.

4.3 Infrastructure Needs for Hydrogen Storage and Transport

4.3.1 Introduction

To meet net-zero 2050 objectives, efforts must begin now to build hydrogen demand and connect the supply to demand. At present, almost all the hydrogen consumed in the world is produced close to the production site. The development of a fuel hydrogen economy will rely on a well-developed infrastructure that can distribute hydrogen safely and efficiently to consumers. Given the abundance of low-cost natural gas and access to low-GHG power in Canada, we could produce hydrogen at a low cost once the required infrastructure is in place, assuming that sufficient CCUS capacity exists near the points of blue hydrogen production and sufficient availability of low-cost electricity for green hydrogen production. However, the distribution and storage of hydrogen are more challenging.
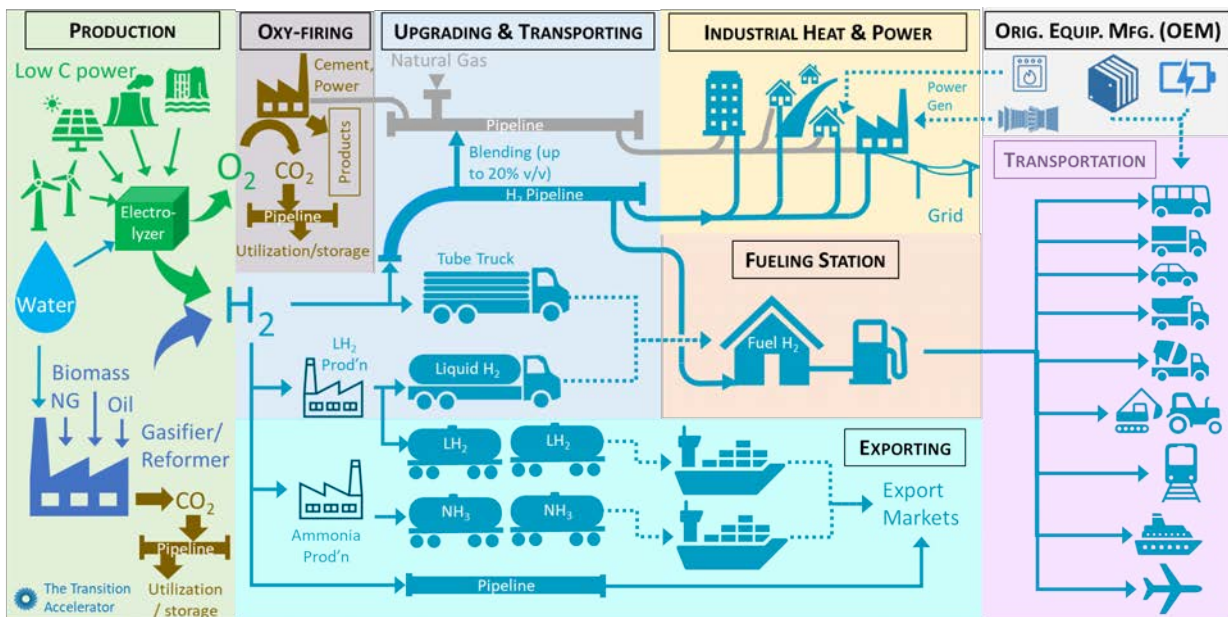
Figure 4.12. Key Value Chains in a Hydrogen Economy.

Hydrogen and the Decarbonization of Steel Production in Canada

The challenge arises from the low density of hydrogen of around 0.0898 kg/m^3 (energy density ~3 kWh$_{LHV}$/m^3) at standard temperature and pressure (STP) of 0 $^\circ$C and 1 atm, respectively [127]. Therefore, a volume of ~11.1 m^3 (11,100 L) would be required to store 1 kg of H$_2$. In contrast, 1 kg of gasoline can be stored in a volume of ~ 0.0013 m^3 (1.3 L) under the same conditions [128]. Compression, liquefaction, or conversion of hydrogen into larger molecules such as ammonia (NH$_3$) are possible options to overcome this hurdle. Thereafter the hydrogen can be transported via either compressed hydrogen trucks, liquid hydrogen/NH$_3$ tanks or via pipelines. The different options in a new hydrogen value chain are shown in **Figure 4.12.** Each option has advantages and disadvantages, and the lowest-cost option will vary according to geography, distance, scale, and the required end-use.

In our recently published report [90], we presented the design and techno-economic analyses of new value chains for delivering hydrogen from centralized production sites to fueling stations supporting heavy-duty vehicles, including trucks, buses, and trains. The results suggested that as a low-density gas, the processing and delivery costs for hydrogen are high. In the early stages of market development with low demand (<1 t$_{H2}$/station/d), compressed hydrogen delivery via tube trailers makes the most sense for short distances, while liquid hydrogen delivery is more attractive for distances over 300 km.

However, the processing and delivery costs with these supply chains (C$3-6/kg$_{H2}$) are too high to be used in heating applications or for the steel industry. In a mature market, dedicated pipeline delivery will offer the lowest delivery costs (<C$1/kg$_{H2}$) if there is large, aggregated demand (~1 t$_{H2}$/day per km of pipeline) to amortize the cost of the transmission pipelines. In the next few sections, we will briefly describe the technologies used for large-scale hydrogen processing and delivery, such as pipeline compression (section 4.3.2), liquefaction (section 4.3.3), pipeline transport (section 4.3.4) and salt cavern storage (section 4.3.5) that will be relevant for the steel industry.

4.3.2 Pipeline Compression

Compression is needed for hydrogen deliveries via compressed hydrogen trucks, liquid hydrogen tanks or pipelines. It is considered to be one of the most expensive steps in the supply chain. This is related to some basic thermodynamic properties of hydrogen.

The energy needed for compressing gases strongly depends on the required molar flow rate, the compressibility of the gas and, to a lesser degree, on the ratio of specific heat. The first factor puts hydrogen at a disadvantage due to its low molar energy density of ~0.066 kWh/mole versus ~0.248 kWh/mole for natural gas. Secondly, while the behaviour of most gases can be approximated using the ideal gas law (PV = nRT), the behaviour of hydrogen deviates significantly from the predictions of the ideal gas model [129]. This deviation results in expansion, i.e., the hydrogen gas occupies more space than the ideal gas law anticipates. This deviation is accounted for using the compressibility factor (Z), whereby Z=1 for an ideal gas. For pressures lower than 600 bar (592 atm), Z is higher for hydrogen versus other gases such as CH$_4$, O$_2$ and CO$_2$ (**Figure 4.13**). Indeed, compressing H$_2$ from 1 bar to 700 bars increases density only 477 times, from 0.0898 kg/m^3 to 42.9 kg/m^3 [130]. This leads to higher compression power requirements for H$_2$ versus other gases due to the direct dependence on Z.
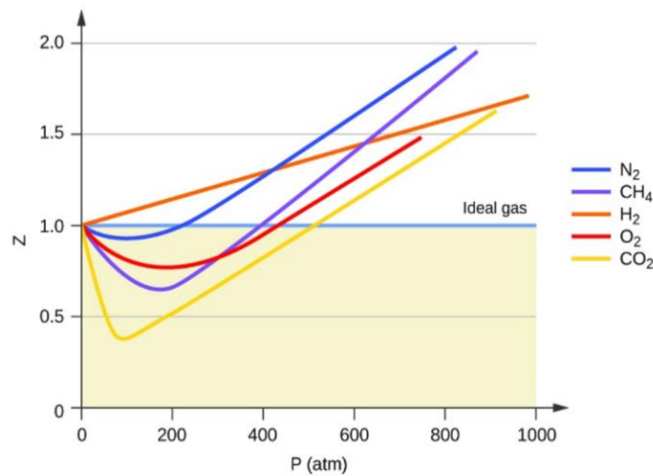
Figure 4.13. Graph of the compressibility factor (Z) versus pressure for various gases at 273 K.
Source: Adapted from Reference [131].

Therefore, compression is the most energy-intensive component of the hydrogen supply chain. If we consider hydrogen gas generated at 20 bar from steam SMR or ATR units, the lowest possible energy to compress H_2 isothermally in a single stage from 20 bar to 350 bar at 20°C is 1.08 kWh/kg H_2 and only 1.48 kWh/kg H_2 to compress from 20 to 700 bar [132]. In practice, greater compression energies are required to reach these high pressures due to compressor inefficiencies and leaks.

In our recently published technical brief on the techno-economics of hydrogen compression [130], we presented a guide on calculating compression power and associated costs and selecting appropriate compressor technology, depending on where compression takes place in the supply chain. Here we will summarize key aspects of hydrogen compression with a focus on large-scale compression for pipelines.

Among various designs, centrifugal compressors (**Figure 4.14**) are most commonly used in applications that require high throughput and moderate compression ratios [133]. They compress the process gas using a rotating impeller with radial blades that imparts kinetic energy to the process gas by increasing its velocity. The kinetic energy is converted to increased pressure using a diffuser. Centrifugal compressors are used for pressurizing air and natural gas in petrochemical plants, refineries, gas gathering, and transmission pipelines. The compression ratio largely depends on the molecular weight of the gas in the centrifugal compressor. Because of the low molecular weight of hydrogen, centrifugal compressors will require impeller tip speeds around 3X higher than those used for natural gas [134,135]. Therefore, when high discharge pressures are needed, the impeller speed must be increased, or additional compression stages must be added. Increasing current impeller tip speeds is very challenging due to material strength limitations and embrittlement issues [135]. Research and development activities over the last few years have led to the evolution of titanium alloy- impellers that can operate with 100% hydrogen at high tip speeds of ~700 m/s, enabling a pressure ratio per stage of 1.26:1 [135]. The design and construction of centrifugal hydrogen compressors is a multifaceted engineering task because it is affected by several interconnected aerodynamic,

thermodynamic, and mechanical parameters and they are currently limited to prototype demonstrations. Nonetheless it can be assumed that these centrifugal compressors will be commercially available in coming years when there is a demand for them.
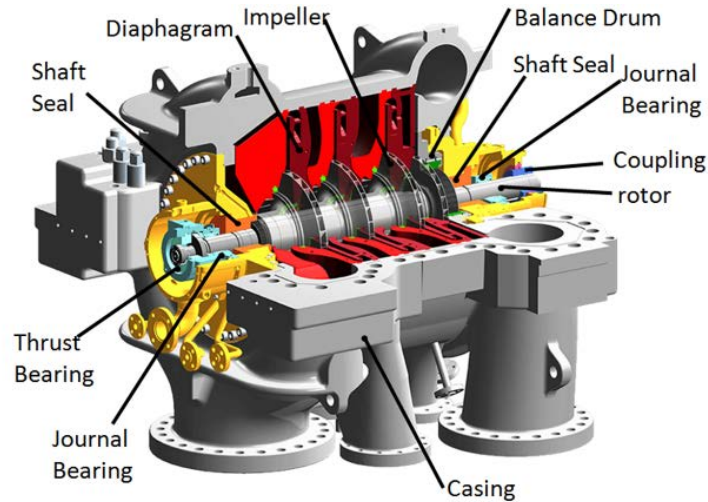
Figure 4.14. Schematic of a centrifugal compressor.
Source: Adapted from Reference [136].

Using the methodology presented in our report on hydrogen compression, we can estimate energy use and cost for large centrifugal compressors driven by an electric motor to be used for hydrogen pipelines. An inlet temperature of 305.15 K, an inlet (suction) pressure of 20 bar and a required outlet (discharge) pressure of 70 bar was assumed. A compression ratio per stage (x) of 2.1, isentropic efficiency (η_{isen}) of 80%, electric motor efficiency of 95% and electricity price of C\$110/MWh is considered for the model.
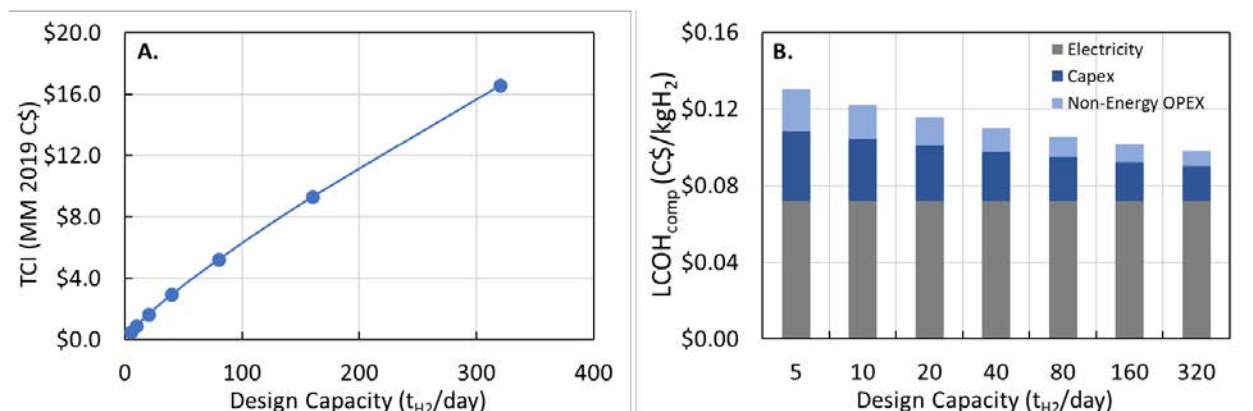
Figure 4.15. Impact of design capacity on (a) TCI (MM 2019 C\$) and (b) LCOH$_{comp}$ (2019 C\$/kg H$_2$) for large-scale centrifugal hydrogen compressors.

The total capital investment (TCI in MM 2019 C$) as a function of compressor size or capacity is shown in **Figure 4.155A** and was calculated using correlations built by the H2A and HDSAM models. The earlier versions of the HDSAM models were based on cost data of two and three-stage reciprocating compressors, which was assembled from data supplied by Air Liquide, Neuman & Esser, Burckhardt Compression, Ariel Compressors, and Dresser-Rand. However, the latest versions of the HDSAM use cost projections based on an existing centrifugal hydrogen compressor design and prototype developed by Concepts NREC for the US Department of Energy (DOE). The cost correlation does not predict a significant cost reduction with compressor capacity with a scaling factor of ~0.83 for TCI. The overall cost of compressing hydrogen (LCOH$_{comp}$) at large scales (5-300 t$_{H2}$/day) and moderate compression ratios (70/20 = 3.5) is low, at around C$0.1/kg$_{H2}$ (**Figure 4.15B**). A breakdown of LCOH$_{comp}$ into CAPEX, electricity and non-energy operating costs shows the dominant contribution from energy/electricity costs. More importantly, the results indicate that at capacities above 100 t$_{H2}$/day, there is no advantage of scaling up compressors. This is because the electricity/energy costs become the dominant contributor to the LCOH$_{comp}$, which is independent of scale/capacity.

It must be noted that the costs presented above can only be realized when hydrogen centrifugal compressors are produced at a large scale and deliver compressed hydrogen without compromising on purity and reliability. The development of new technologies, such as those based on ionic liquids or metal hydrides, is also promising. In particular, ionic liquid compressors developed by Linde could be the key to efficient and low-cost hydrogen compression. These compressors do not require bearings or seals, two common sources of failures in piston and diaphragm compressors.

4.3.3 Liquid Hydrogen Production

Liquid hydrogen supply is often desired due to its higher density (70.8 kg/m^3) compared to gaseous hydrogen (0.0898 kg/m^3) at 1 bar and compressed hydrogen (42.9 kg/m^3) at 700 bars. A conventional hydrogen liquefaction process involves three main steps [137]: compression, cooling (via liquid nitrogen and heat exchangers) and expansion, as shown in **Figure 4.16**. High-purity (> 99.99%) gaseous hydrogen is initially compressed to ~2-8 MPa. Thereafter, hydrogen is cooled to below its inversion temperature of 80 K, to ensure the temperature will decrease during the expansion step. The cooling is typically done in two steps. Hydrogen is first cooled to ~80 K using the Claude cycle with a liquid nitrogen bath and a heat exchanger [137]. In the second step, a second heat exchanger is used to drop the temperature of hydrogen to ~40 K. Finally, hydrogen is expanded to low pressures (~1.3 bar) via a throttling process where hydrogen cools to 20 K and partially liquefies.

The minimum theoretical energy to liquefy hydrogen from ambient (300 K, 1.01 bar) conditions is 3.3 kWh/kg$_{H2}$ or 3.9 kWh/kg$_{H2}$ with conversion to para-H$_2$ [132]. Ortho and para refer to the orientations of the two nuclear spins in the hydrogen molecule, where ortho is in the same direction and para in opposite directions. This is significant because normal, gaseous hydrogen approximately 25% para-hydrogen and 75% ortho-hydrogen, whereas liquid hydrogen is over 99% para-hydrogen [138]. The conversion to para (and liquid) occurs at hydrogen's boiling point (20 K) but is very slow in the absence of a catalyst. Therefore, modern liquefiers use catalysts inside heat exchangers to accelerate the conversion.
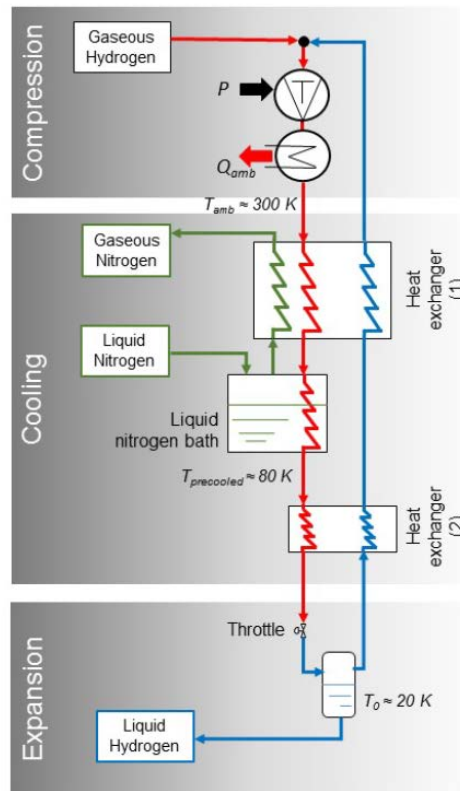
Figure 4.16. Joule–Thomson process with liquid nitrogen precooling.

Source: Adapted from Reference [137].

Today's industrial liquefiers, however, have an energy requirement in the range of 8-12 kWh/kg$_{H2}$ with capacities of 5,000-200,000 kg LH$_2$/day [137]. The largest liquefier in operation in the US today is about 70,000 kg LH$_2$/day [137]. In addition to being energy intensive, hydrogen liquefaction plants also have high capital costs. A recent liquid hydrogen production plant has been publicly reported to cost US$150 million for a capacity of 27,000 kg/day serving the California market. Air Products' new hydrogen complex in Edmonton, Alberta, expected to come on-stream in 2024, will comprise of a 35-tonne liquefaction facility to help accelerate the use of hydrogen as an emission-free transportation fuel.

In our recent report [90], we summarized the costs of an LH$_2$ terminal consisting of the liquefier unit and the LH$_2$ terminal facility consisting of pumping and storage equipment at different scales, from 10 t$_{H2}$/day to 100 t$_{H2}$/day. The results (**Figure 4.17**) indicate that hydrogen liquefaction will cost anywhere between C$3-5/kg$_{H2}$, depending on the scale of the terminal. To that end, liquefier units have better economies of scale. The breakdown of costs shows the dominant role of CAPEX, contributing between 40-50% to the total terminal cost, which is a result of the high cost of compressors and liquefier units.
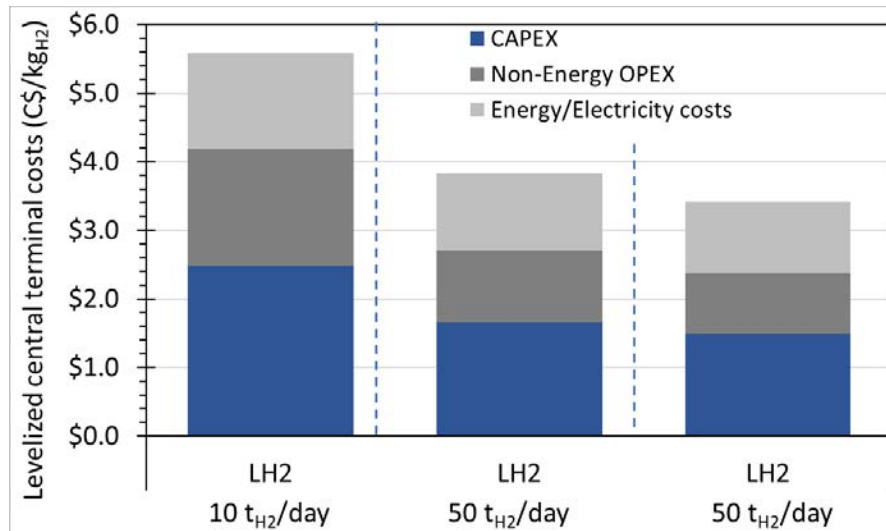
Figure 4.17. Liquid hydrogen central terminal costs (C\$/kg$_{H2}$) as a function of terminal size (t$_{H2}$/day) and divided into CAPEX, non-energy OPEX and energy/electricity costs.

4.3.4 Pipelining Hydrogen

Truck transport of compressed gaseous or cryogenic liquid hydrogen can move smaller amounts of gas (1 to 4 t$_{H2}$/truck), but the costs per km-kg$_{H2}$ are significant [90] and would eliminate most applications for hydrogen at a large scale, such as in heating and the steel industry. Pure hydrogen pipelines hold the most promise for the large-scale and low-cost deployment of hydrogen. Transporting hydrogen via pipelines can be an effective delivery method connecting central or distributed production sites to customers.

The transportation of hydrogen 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 [139]. There are ~2500 km of active hydrogen pipelines in the United States today, and over 90% of these pipelines are located along the Gulf Coast, primarily connecting major hydrogen producers with well-established, long-term customers such as refineries and ammonia plants [140,141]. Similarly, Canada also has several hundred kilometers of process pipelines transporting hydrogen inside facilities, like refineries, but built mainly on pipe racks above ground. A 48 km transmission pipeline connects Air Products' hydrogen production facilities in Strathcona County near Edmonton to customers in Fort Saskatchewan [95]. The company also operates a hydrogen production facility, a 30-kilometre pipeline network and a liquefaction facility in Sarnia, Ontario [142].

The transition to a hydrogen economy will also significantly depend on how effectively and quickly we can adapt our current natural gas pipeline infrastructure for hydrogen transmission. However, a key challenge with the use of natural gas transmission pipelines is around the issue of hydrogen embrittlement. Most gathering and transmission pipelines are made from carbon steel or stainless steel with a diameter of 4-48 inches [140,143]. High-strength steels (above 100 KSI), which are often used in natural gas transmission pipelines, are more susceptible to hydrogen embrittlement. Hydrogen embrittlement leads to a decrease in ductility of the steel and its tensile strength due to the absorption and diffusion of hydrogen atoms or molecules [144]. Hydrogen molecules may dissociate at the surface of the steel pipe into two H atoms which

may then diffuse deeply 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 4.18A**. These bubbles cause stress and intergranular cleavage, eventually leading to cracking and rupture, [145] as shown in **Figure 4.18B**. During operation, significant pressure fluctuations accelerate the embrittlement process, with reported fatigue crack growth rates an order of magnitude higher. Equally important, optimization and quality check of welding joints is paramount with these joints being most prone to H_2 embrittlement.
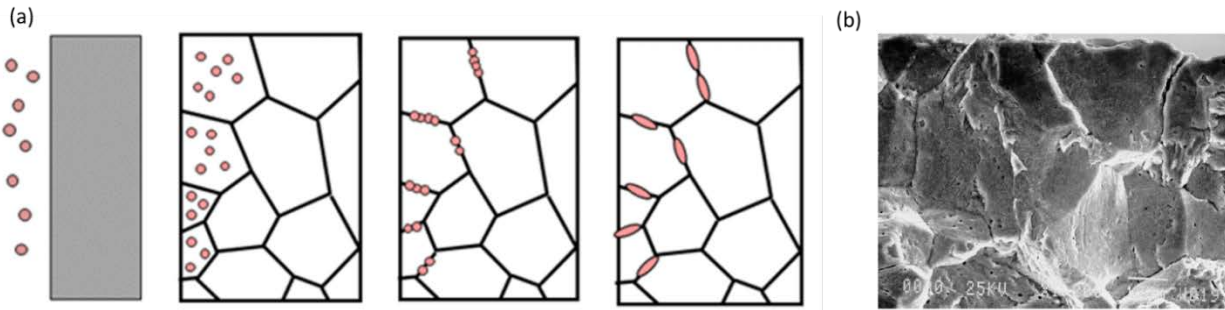
Figure 4.18. (a) Schematic of hydrogen embrittlement process in carbon steel. (b) Scanning electron microscopy (SEM) image revealing intergranular cleavage, characteristic of hydrogen embrittlement.
Source: Adapted from References [144,146].

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 [139,145]. However, using lower-grade steel means lower operating pressures are possible or the wall thickness will need to be increased to accommodate the high operating pressures of transmission pipelines.

Another important issue is around the energy that can flow in a pipeline used to transport natural gas versus hydrogen. While hydrogen has a high energy density per unit mass (120 MJ/kg, LHV) versus methane (50 MJ/kg, LHV), the challenge arises due to its low volumetric energy density (10.78 MJ/m^3, LHV), which is ~ 3.29 times lower than methane (35.5 MJ/m^3) [147]. In other words, to ensure the same energy content in the pipeline, hydrogen flow rates will have to be 3.29 times higher than for 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 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 hydrogen can be ~2.91 times higher than methane. Thus, the maximum flow rate of hydrogen can be 2.91 times higher than methane. Therefore, the maximum energy density of a hydrogen pipeline is limited to ~ 2.91/3.29 = 88.4% of the energy content of a methane pipeline. The calculation has been summarized in **Table 4.6**.

It is important to highlight that the higher flow rates needed for hydrogen 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 supplied as hydrogen than as natural gas. This was described in more detail in Transition Accelerator's technical brief on hydrogen compression [130].

Table 4.6. Energy content of pipeline carrying hydrogen versus methane.

Parameter	Methane	Hydrogen
LHV (MJ/kg)	50	120
LHV (MJ/m^3)	35.5	10.78
Required flow rate (m^3/s) to get the same energy flowing through a 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**

In our recent report on hydrogen transport using transmission pipelines [148], we demonstrated detailed gas flow and cost calculations of a 1500 km hydrogen transmission pipeline. The costs were calculated for different pipeline sizes from 10-inch to 48-inch with compressor stations placed every 500, 300 or 100 km. The inlet pressure was assumed to be 70 bar, and outlet gas velocity was at 35 m/s, assuming a pipe roughness of 0.0178 mm and flow temperature of 228.1 K. A reciprocating compressor with a compression ratio per stage (x) of ~2.1, an isentropic efficiency (η_{isen}) of ~80% and a motor efficiency ~95% is considered for compression.
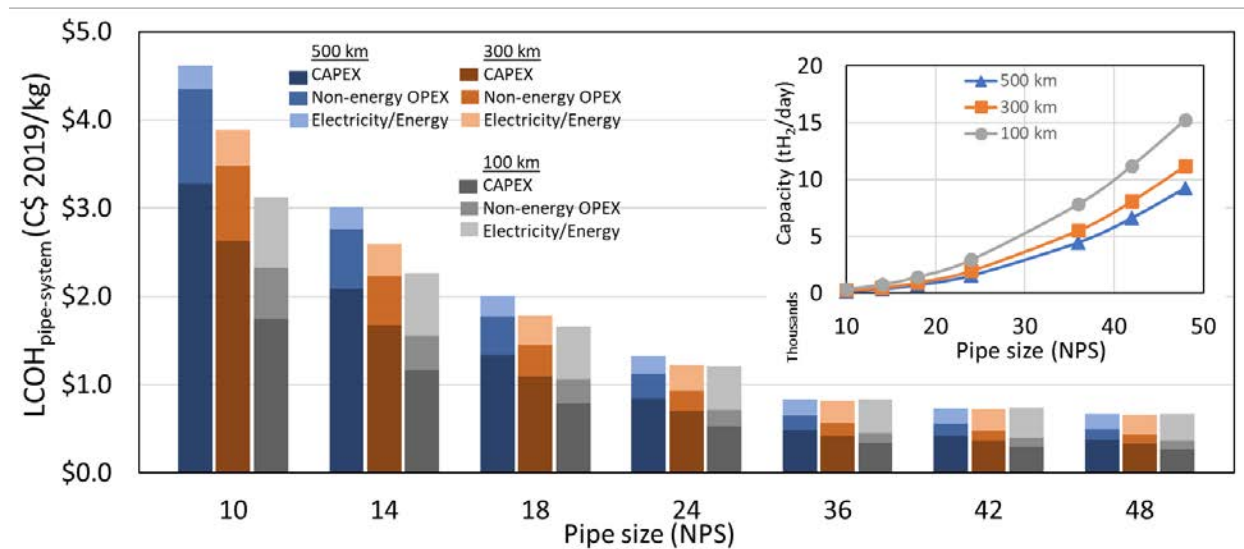
Figure 4.19. LCOH$_{pipe-system}$ is divided into: CAPEX$_{pipe-system}$, Non-Energy OPEX$_{pipe-system}$ and Electricity /Energy$_{pipe-system}$ versus pipe size (NPS). Inset: Pipeline H$_2$ capacity (t$_{H2}$/day) versus pipe size (NPS) as a function of the distance between compressor stations.

The inset of **Figure 4.19** shows the maximum hydrogen transportation capacity of a pipeline as a function of nominal pipe size (NPS). The pipeline capacity is calculated from the flow rates for different pipe lengths (500, 300 and 100 km). As expected, the capacity increases with larger pipe size, from ~183 t$_{H2}$/day for a 10-inch pipeline to ~ 9235 t$_{H2}$/day for a 48-inch pipeline with compressor stations placed every 500 km.

With an increase in the 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 is primarily due to a lower pressure drop in the pipeline over a shorter pipe length of 100 km versus 500 km.

The LCOH analysis for pipeline transport ($LCOH_{pipe-system}$) as shown in **Figure 4.19** reveals two key features. Firstly, for a total distance of 1500 km, pipeline transportation of hydrogen will only make economic sense with large (>24 NPS) pipelines that are capable of delivering thousands of t_{H2} per day. For large pipelines (36-49 NPS), it would be possible to transport hydrogen at under C$1/$kg_{H2}$ over 1500 km. Secondly, adding additional compressor stations to increase pipeline capacity can benefit smaller pipes (<24 NPS), decreasing the levelized cost of hydrogen 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 hydrogen transported. With the use of larger pipes, the additional compressor stations do not add any benefit in terms of reducing LCOH. 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 a significant reduction in CAPEX and non-energy OPEX costs, which makes up for the extra electricity costs. This is not the case for larger pipes (>24 NPS).
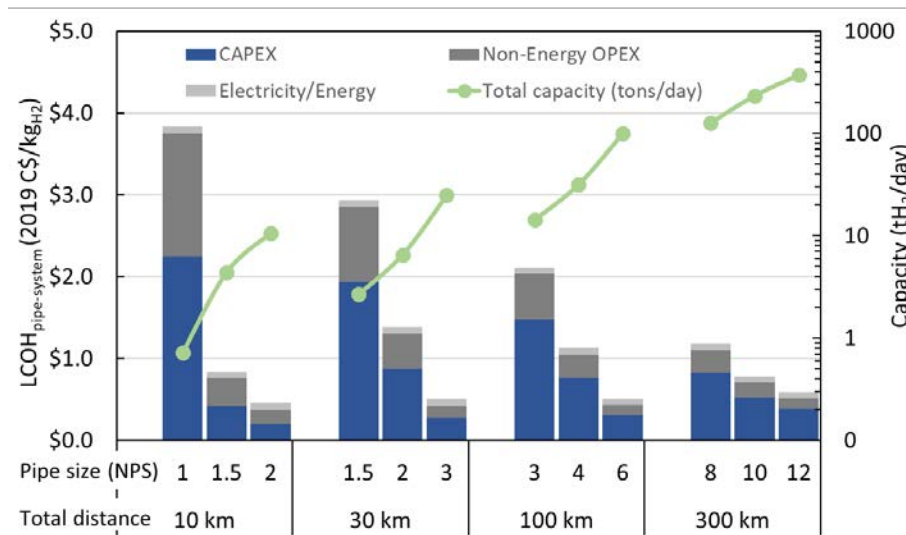
Figure 4.20. LCOH$_{pipe-system}$ **divided into: CAPEX**$_{pipe-system}$**, Non-Energy OPEX**$_{pipe-system}$ **and Electricity /Energy**$_{pipe-system}$ **at different pipe sizes (NPS) and pipeline lengths, versus resulting capacities.**

In the report [148], we present the techno-economic results of hydrogen transport via transmission pipelines across shorter distances of 10, 30, 100 and 300 km. This was done assuming only an inlet compressor station that compresses hydrogen from 20 to 70 bars, which is the inlet pressure of the pipeline. **Figure 4.20** 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 ~C$0.5-0.6/$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 a function of the total distance from ~10.5 t_{H2}/day for 10 km to ~ 370 t_{H2}/day for a 300 km

pipeline. The results lead us to propose a rule of thumb: "**We roughly require a demand ~1.0-1.2 t_{H2}/day per km of pipeline to drive economic viability.**" This applies to short-distance pipelines without compressor stations along the length of pipeline.

4.3.5 Large-scale storage of hydrogen

Hydrogen can be stored on a small scale (~1 t_{H2}/tank) in compressed hydrogen tanks at 350-950 bars. These storage tanks have to be reinforced with carbon fiber for safety reasons, which increases the cost [149]. Moreover, compression of hydrogen to these high pressures consumes a significant amount of energy, with ~ 2.5-3 kWh_e required per kg of hydrogen to compress from 20 bars to 350 bars [130]. This makes compressed hydrogen tanks impractical for large-scale storage.

Large-scale deployment and use of hydrogen will require low-cost solutions to store hydrogen at different scales (quantity) and lengths (time). Large-scale or bulk hydrogen storage has been investigated in LH_2 tanks, underground pipelines, lined rock caverns and salt caverns. LH_2 storage as a cryogenic liquid at 20 K has been proven at medium to large scales. The largest LH_2 storage facility is at NASA's Kennedy Space Center with two 3200 m^3 spheres (21.3 m in diameter), each capable of storing 230 tonnes of LH_2 [150]. However, as discussed in section 4.3.3, liquefaction requires significant energy, making it impractical for most applications.

Underground storage in geological sites is expected to be the most economical method for storing substantial amounts of hydrogen. It has been widely used for natural gas storage, meeting seasonal and peak demand. In Canada, natural gas is injected into storage during the summer months when demand is lower and is withdrawn during winter when demand for space heating increases. Underground natural gas storage facilities in Canada are located in five provinces: Alberta, British Columbia, Ontario, Quebec, and Saskatchewan. The combined capacity of all underground storage facilities in Canada is 949 bcf. The majority of this capacity (548 bcf) is located in Alberta, followed by Ontario with 248 Bcf [151].

The majority (80-90%) of the underground storage is provided by depleted natural gas fields and the rest by aquifer reservoirs and salt caverns [152]. To date, hydrogen storage has been demonstrated in salt caverns but not in depleted gas fields or aquifers, which require a caprock to seal hydrogen [153]. The high diffusivity of hydrogen can result in losses in porous underground formations. In the case of aquifers, hydrogen could potentially be lost by dissolving in the large contact area with the surrounding brine.

Pure hydrogen has been successfully stored without losses in salt caverns at three locations: three caverns in Teesside, U.K., since 1972 (200,000 m^3), one in Clemens, TX, since 1983 (580,000 m^3), and a more recent one in Moss, Texas since 2007 (566,000 m^3) [153]. Salt caverns are artificial cavities in underground rock salt (halite) formations created by the solution mining process where halite is dissolved and removed in a controlled manner by water injection [154].
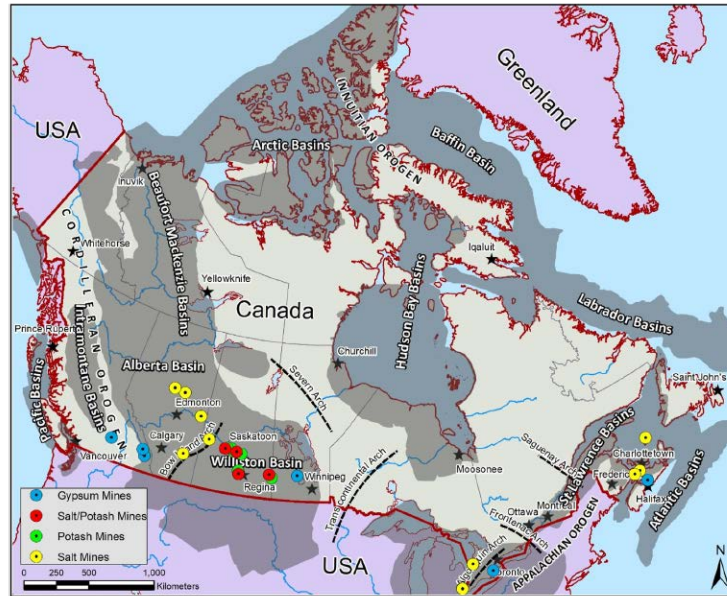
Figure 4.21. Salt mines in Canada.

Source: Adapted from References [155].

Halite is both tight and inert to liquid and gaseous hydrocarbons and to other gases, including hydrogen. The physical and behavioural properties of halite enable the construction and operation of very large facilities that are stable for long periods of time. In Canada, major rock salt (halite) deposits are located in the provinces of Alberta, Saskatchewan, Manitoba, Ontario, New Brunswick, and Nova Scotia (**Figure 4.21**). **Table 4.7** summarizes the attributes of pipe and salt cavern storage as the two most promising solutions discussed in the literature.

Table 4.7. Attributes of bulk hydrogen storage methods.

Source: Adapted from Reference [153].

Attribute	Pipe storage	Salt Cavern
Storage Pressure (bar)	7-100	55-150
Outer diameter (inches)	18-36 inches	--
Individual pipe Length (m)	12	--
Roof Depth (m)	--	150-1200
H_2 storage capacity (tonnes)	20-500	500-6000
Application	City Gate	City Gate

In a recently published study [153], Papadias and coworkers analyzed the techno-economics of bulk hydrogen storage in underground pipelines and salt caverns. The study revealed that at small scales (<20 t_{H2}), underground pipes are more economical than geological caverns. However, salt cavern storage exhibits decreasing costs with scale, and at a storage capacity of 500 tonnes, salt cavern storage is significantly cheaper, at US$0.14-0.21/$kg_{H2}$ versus underground pipeline storage at US$1.84-2.36/$kg_{H2}$.

5 A CASE STUDY FOR THE USE OF HYDROGEN FOR THE DIRECT REDUCTION OF IRON IN THE HAMILTON REGION

5.1 Introduction

In Canada, steel is produced in five provinces (Alberta, Saskatchewan, Manitoba, Ontario, and Quebec), with the industry concentrated in Ontario [156], accounting for 72% of the country's steel (**Figure 5.1**). With the decommissioning of the blast furnace and steelmaking operations at the Stelco integrated plant in Hamilton [157], there are currently three integrated and nine electric arc furnace (EAF) plants in Canada, with the share of steel produced via the EAF route at around 40% [158].

Canada Steel Production: 13.2 Mt/year
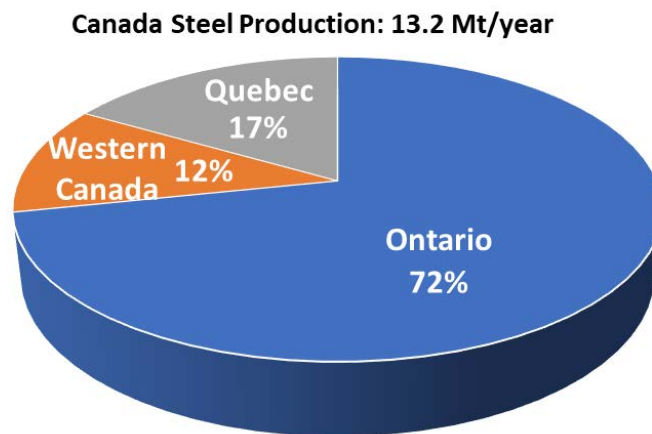
Figure 5.1. Canadian steel production.

Source: Discussions with Canadian Steel Producers Association.

In Ontario, the region of Hamilton has for more than a century proudly borne the title: 'Steel Town'. Its life, economy and physical environment is dominated by the steel industry: Hamilton and nearby regions of Nanticoke and Sault Ste. Marie are home to the three integrated steel plants of Canada with a combined annual production of 8-10 million tonnes of steel. The region also has four EAF plants, as summarized in **Table 5.1**. As discussed in Chapter 3, while the decarbonization strategy for EAF plants involves using low-GHG electricity, integrated steel mills are more likely to pursue a wide range of decarbonization options to reach net-zero emissions (**Table 5.1**).

Table 5.1. Steel production facilities in Ontario, Canada.

Source: Adapted from References [156,159].

Number	Location	Name	Technology	Low-GHG Strategy
1	L'Orignal	Ivaco Rolling Mills	Electric Arc Furnace	Use of low-GHG electricity
2	Sault Ste Marie	Algoma Steel Inc.	Integrated Mill – BF/ BOF	Towards EAF with low-GHG electricity [160]
3	Cambridge	Gerdau	Electric Arc Furnace (idled)	Use of low-GHG electricity
4	Whitby	Gerdau	Electric Arc Furnace	Use of low-GHG electricity
5	Nanticoke	Stelco	Integrated Mill - BF/ BOF	Pending with use of low-GHG electricity
6	Welland	Valbruna ASW Inc	Electric Arc Furnace	Use of low-GHG electricity
7	**Hamilton**	**ArcelorMittal Dofasco**	**Integrated Mill - BF/BOF + EAF**	**NG-DRI to H2-DRI** [161]

Note: Facility #7, highlighted in bold text, is assessed in this study for conversion to H_2 DRI-EAF plants.

Algoma Steel Inc. in Sault Ste Marie has announced the transformation of its integrated steel plant to EAF in its low-GHG strategy [160]. On the other hand, ArcelorMittal Dofasco will move to a DRI-EAF facility [161]. The plant will initially operate on natural gas but will be constructed to be hydrogen ready. Lastly, while details have not been announced, Stelco has indicated that it will pursue an aggressive decarbonization pathway that differs from the other integrated facilities in Ontario while maintaining the high quality of its output.

To assess the potential hydrogen demand in the integrated steel industry, we only considered the announced ArcelorMittal DRI facility, capable of producing 2.5 million tonnes of DRI per year and 2.4 million tonnes of steel in an EAF facility. Based on the design of a combined Midrex[3] and electric arc furnace (EAF) process [162] (i.e., the H2-DRI-EAF route), we can calculate the potential hydrogen demand.

As described in Chapter 3, the Midrex and HYL processes are the most widely used gas-based direct reduction processes in the world that employ a shaft furnace as the reactor and use H_2-rich gas as a reducing agent. The hydrogen content of the reducing gas in the Midrex and HYL processes was approximately 55–58 and 84–86%, respectively [163]. There have been various studies analyzing the use of 100% hydrogen in the shaft furnace direct reduction process whereby pure hydrogen can be produced either internally or externally within the process. For a Midrex H_2 process using 100% hydrogen, the reported hydrogen consumption is ~ 550 Nm^3 per tonne of direct reduced iron (DRI) [28]. Additionally, up to 250 Nm^3 per tonne of DRI is required as fuel for the reduction gas heater [28]. Furthermore, the total electricity requirement for the EAF facility was also calculated using the reported electricity requirement of 450 kWh per tonne of steel for the EAF unit [164]. The results of our analysis reveal that **~492 t_{H2}/day** and **~2959 MWh/day** will be required by the facility.

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[3] Other technologies, such as Energiron, may be used but hydrogen demand would not differ materially between competing DRI technologies.

5.2 Green versus Blue Hydrogen Production: Feasibility

A hydrogen demand of 492 t_{H2}/day is significant and is equivalent to 6% of Canada's current total production of approximately 8200 t_{H2}/day [89,90]. As discussed in section 4.2.2., the current state-of-the-art PEM electrolyzer system requires approximately 55 kWh of energy (including the balance of plant) and 10 kg of water to produce 1 kg of hydrogen. Therefore, producing 492 t_{H2}/day via electrolysis would require 27 GWh/day of low-GHG electricity (**Table 5.2**). This is equivalent to ~ 6.5% of all of Ontario's current electricity generation [165], which was at 153 TWh per year in 2019.

Table 5.2. Electricity required to produce the potential hydrogen demand from the ArcelorMittal DRI facility via electrolysis.

Parameter	Value
Potential Hydrogen Demand (t/day)	492
Electrolysis Electricity Requirement (MWh/t_{H2})	55
Total Electricity Requirement for Electrolysis (GWh/day)	**27**

It is important to assess the feasibility of producing 27 GWh/day of low-GHG electricity in the transition to net-zero by 2050. Ontario currently produces 92% of its electricity from low-GHG sources: 59% from nuclear, 24% from hydroelectricity, 8% from wind, and 1% from solar.

The three nuclear power plants in Ontario, i.e., Bruce Power, Darlington, and Pickering are currently providing 247 GWh of low-GHG electricity per day. An additional demand of 27 GWh per day would be approximately 11% of all the electricity generated by nuclear facilities in the province.

On the other hand, Ontario currently only produces 1% of its electricity from solar. Although the province receives decent solar irradiation, the high population density makes it challenging to install and operate large photovoltaic power plants.
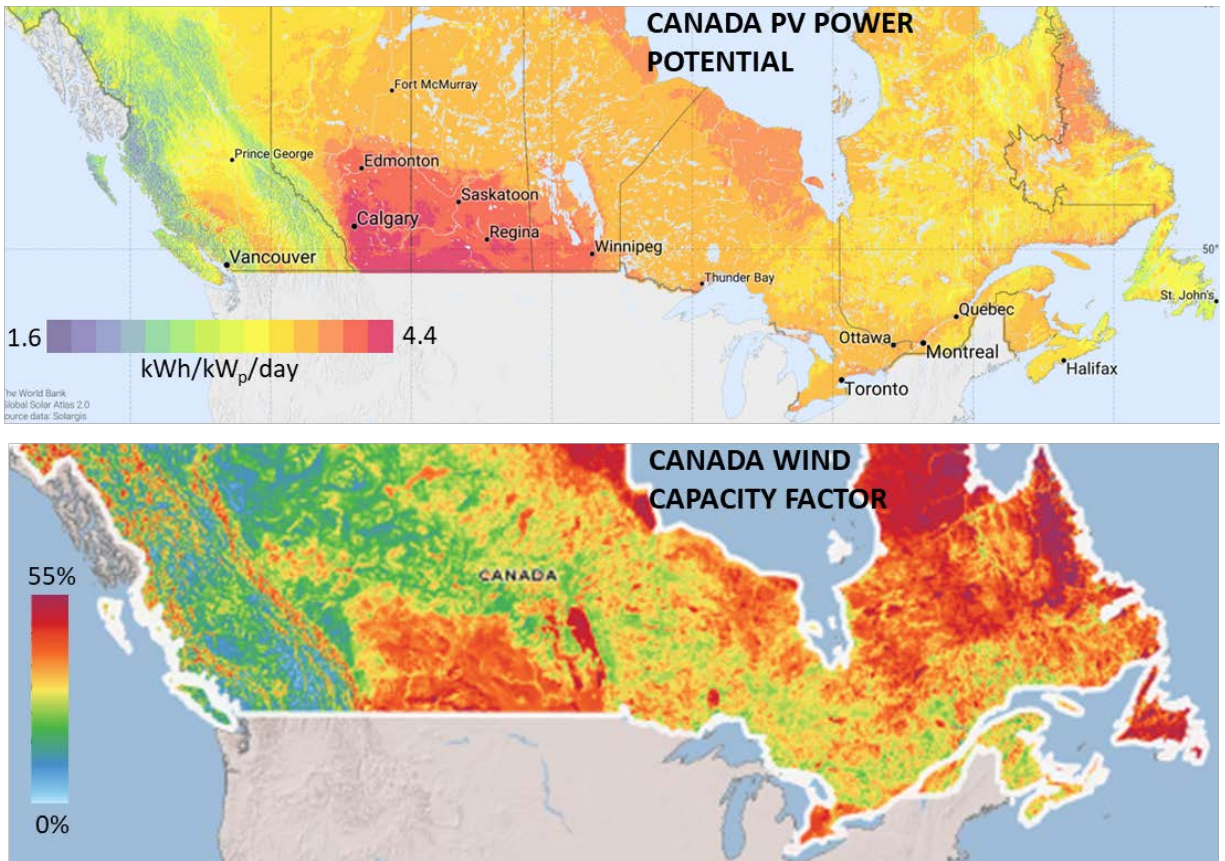
Figure 5.2. (A) Solar Resource Map of Canada showing annual photovoltaic potential (kWh/kW/year) and (B) Wind Resource Map of Canada showing average annual capacity factor (%).

Figure 5.2 shows the solar and wind resource map of Canada. The mean daily global insolation based on 2-axis tracking in southern Ontario is approximately 6 kWh/m^2/day [166]. At the same time, the photovoltaic potential is 3.84 GWh/GW/day [166]. Generating 27 GWh/day of low-GHG electricity via solar power would require the installation of 7.1 GW of PV panels. For a perspective, by the end of 2022, Canada had a total of 4 GW of installed solar PV capacity, [167] and the biggest PV farm in the world is a 2.2 GW solar park in India [168]. Additionally, a solar farm of this size would occupy an area of 84 sq. km, based on the expected efficiency of a utility-scale PV module in 2030 of 21.5% [169].

Table 5.3. Solar PV capacity needed to produce electricity to make 492 t_{H2}/day in Southern Ontario.

Parameters	Value
Required electricity (GWh/day)	27.0
Mean daily global insolation (kWh/m^2/day) [166]	6.00
Photovoltaic Potential (GWh/GW/day) [166]	3.84
PV module efficiency (%)	21.50%
Power produced by PV module (kWh/m^2/day)	1.29
Power produced by PV module (GWh/m^2/day)	1.29E-06
Area of PV modules needed (m^2)	2.1E+07
PV packing factor (%) [170]	25%
Area of PV power plant needed (m^2)	8.4E+07
Area of PV power plant needed (km^2)	**84**
Size of PV power plant (GW)	**7.1**

Similarly, Southern Ontario has good wind resources with an average capacity factor of 0.4 and mean power density between 400-500 W/m^2 [171]. Generating 27 GWh/day of low-GHG electricity from wind will require 2.82 GW of wind turbines. Modern power plants in the United States have been reported to take up a total area, i.e., the land area associated with the complete wind plant of 0.35 hectares/MW or 0.35 km^2/MW [172]. Thus, installing a 2.82 GW wind power plant would take up a total area of approximately 987 km^2. To give a perspective, at the end of 2022, Canada had a total installed wind energy capacity of 15 GW, with Ontario having a total installed wind capacity of approximately 5.5 GW.

Table 5.4. Wind capacity needed to produce electricity to make 492 t_{H2}/day in Southern Ontario.

Parameters	Value
Required electricity (GWh/day)	27.0
Average Capacity Factor [171]	0.4
Average Area (hectares/MW) [172]	35.0
Average Area (km²/MW)	0.35
Area of wind power plant needed (km^2)	**987**
Size of wind power plant (GW)	**2.82**

Our calculations summarized in **Tables 5.3** and **5.4** demonstrate the scale of the challenge of producing green hydrogen in the near future. It can widely be expected that most additional wind or solar capacity that comes onto the grid in the next 10-15 years will be used to electrify and decarbonize sectors such as power generation, transport, and heating.

At the same time, the cost and capacity factor of the available low-GHG electricity will be critical to make low-cost hydrogen via water electrolysis. As described in section 4.2.2, even in a 2040 scenario, we would require low-GHG electricity with electricity prices under C\$50/MWh, available for 3000+ hours/year, to produce green hydrogen at under C\$3/kgH$_2$.

If the integrated steel industry in Hamilton Region is to transition to hydrogen use, it is safe to assume that a majority of this demand will have to be fulfilled by blue hydrogen (i.e., via methane reforming coupled with CO_2 capture and sequestration). In the next couple of sections, we will summarize potential sites for large-scale underground CO_2 storage (section 5.3) and the cost of blue hydrogen supply at this scale (section 5.4).

5.3 Carbon dioxide storage potential in Southern Ontario

Three main types of geological formations are being considered for underground CO_2 injection [173] and sequestration: (1) depleted oil and gas reservoirs, (2) deep saline reservoirs, and (3) un-mineable coal seams.

CO_2 is injected at depths greater than about half a mile (800 meters) in a typical reservoir; the pressure keeps the injected CO_2 supercritical, making the CO_2 less likely to migrate out of the geological formation [173]. The process also requires that the geological formation has an overlying caprock or relatively impermeable formation, such as shale, so that injected CO_2 remains trapped underground [173]. Injecting CO_2 into deep geological formations uses existing technologies that have been primarily developed and used by the oil and gas industry, and that potentially could be adapted for long-term storage and monitoring of CO_2.

Canada has a geological landscape that has tremendous potential for permanently storing large volumes of CO_2 underground. According to the CO_2 Storage Resource Catalogue, which has compiled global storage potentials, Canada's sum of its storage resources is 398 Gt in deep subterranean geological formations known as basins [174]. The majority of this potential is in Western Canada's "Alberta" basin and "Williston" basin, and the rest is in Eastern Canada's "Quebec" basin and "Michigan" basin.

Southern Ontario sits amid potential gas storage opportunities. The region is currently home to one of the largest natural gas storage facilities in North America, referred to as the Dawn Hub (**Figure 5.3**). Ontario's unique Dawn Hub is also the second most physically traded natural gas hub in North America and is in close proximity to the steel plants in Hamilton and Nanticoke [175].
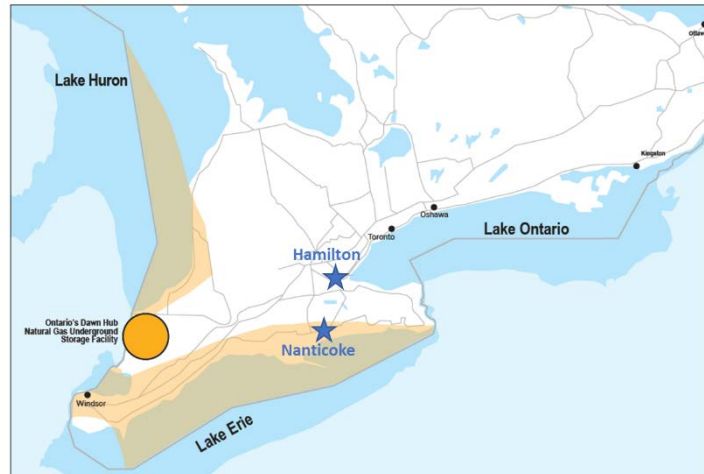
Figure 5.3. General Area of saline aquifers with CO$_2$ storage potential and existing natural gas storage in Ontario.

Source: Geological Sequestration of Carbon Dioxide. A technology review and Analysis of opportunities in Ontario, Ontario Ministry of Natural Resources, 2007 [176].

The Dawn Hub is a series of underground depleted cavernous natural gas reservoirs that are filled each summer when demand for natural gas is low and natural gas is cheaper. It is then discharged in the winter to serve increased heating demand. This allows optimum utilization of pipeline capacity in Ontario, lowers natural gas prices for Ontario families and businesses, and ensures the province has the energy it needs throughout the winter. Each year, Ontario stores approximately 35% of its total winter natural gas demand in the Dawn Hub storage facilities [175].
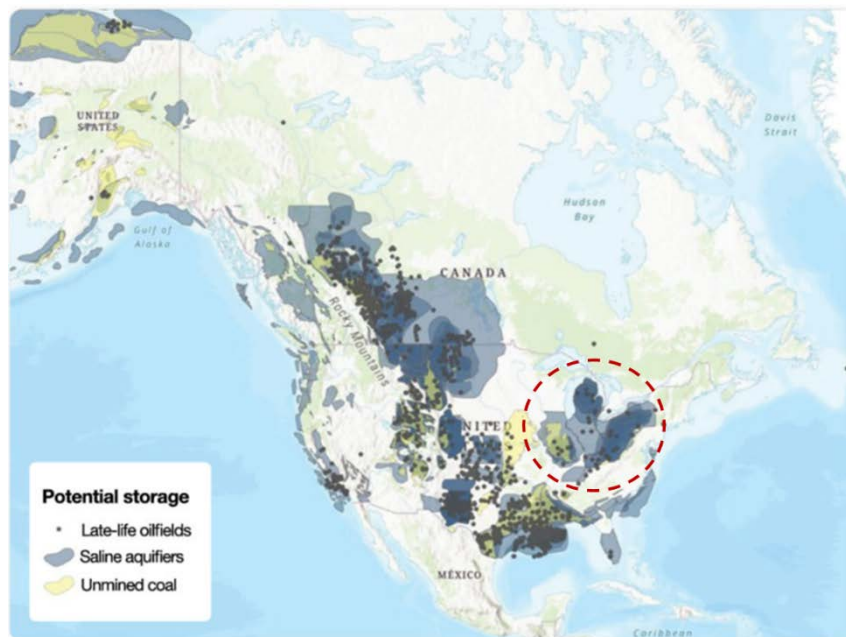
Figure 5.4. Potential CO$_2$ storage sites in North America.

Source: Adapted from Reference [96].

The region also has tremendous CO_2 storage opportunities as well. The Appalachian and Michigan basins, two of the largest sedimentary basins in eastern North America, stretch across multiple US states and reach Ontario at its southern border [96]. On the Ontario side of these basins, saline aquifers have been identified as potential carbon storage options. Saline formations represent an enormous potential for CO_2 storage, and recent project results suggest that they can be used as reliable long-term storage sites [97]. While the assessed storage potential in Ontario itself is comparatively small [174], the majority of potential extends across the border into the states of Michigan, Ohio, and Pennsylvania (**Figure 5.4**).

The total CO_2 storage potential in just the three surrounding states across the border from Ontario is between 60-98 billion tons (54.4-88.9 billion tonnes) of CO_2 (**Table 5.5**). These estimates do not include economic or regulatory constraints; only physical constraints are applied to define accessible parts [97].

In a scenario where blue hydrogen has to be produced for the steel industry, it is likely to be produced in one of the neighbouring states in the United States and then transported to the Hamilton area via a pipeline. In the next section, we break down the cost of this hydrogen value chain at a supply scale of 492 t_{H2}/day, as calculated in section 5.1.

Table 5.5. CO_2 storage potential in billion metric tons

Source: Carbon Storage Atlas, 2015 [97].

State	Oil and NG Reservoirs Storage		Unmineable Coal Storage		Saline Formation Storage		Total Storage	
	Low	High	Low	High	Low	High	Low	High
Michigan	0.17	0.32	0	0	31.55	66.2	31.72	66.52
Ohio	0.65	1.97	0.12	0.12	9.91	9.91	10.68	12
Pennsylvania	0.8	2.45	0.27	0.27	17.34	17.34	18.41	20.06
Total	**1.62**	**4.74**	**0.39**	**0.39**	**58.80**	**93.45**	**60.81**	**98.58**

5.4 Cost of Hydrogen Supply to the Steel Industry

While distributed hydrogen production may have a significant role in the future and supply hydrogen to the steel industry, the scale of demand from an integrated steel plant means that a substantial system will be required for producing and transporting hydrogen to where it is needed.

Dedicated hydrogen pipelines for large-scale, low-cost transport of hydrogen [148]. Long distance transportation via high-pressure pipelines is still challenging due to hydrogen embrittlement [148]. However, it is expected that the use of thicker low-strength steel, engineering solutions such as coatings and better integrity management systems and sufficient demand will see the buildout of pure hydrogen pipelines in the near future. Norway and Germany have already announced a plan to build a hydrogen pipeline between the two countries by 2030 [177].

Figure 5.5 shows the design of a value chain to deliver low-GHG hydrogen to the integrated steel industry in the Hamilton region. Hydrogen will be produced in centralized production facilities that use either steam methane reforming or autothermal reforming for hydrogen production. These will be coupled to CO_2 capture systems described in section 4.2.1. be near sequestration sites, and the captured CO_2 is transported via a 100-km CO_2 pipeline.
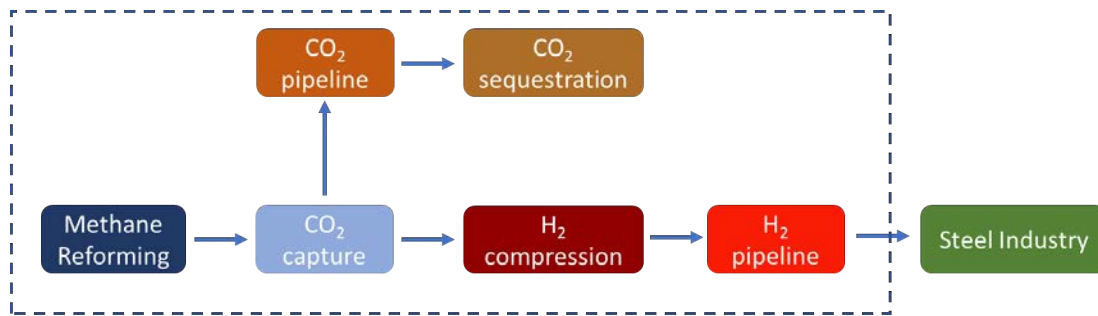
Figure 5.5. Dedicated value chain to deliver hydrogen from centralized production sites to H2DRI-EAF steel plants.

The hydrogen produced at 20 bars from the centralized facility is compressed to 70 bars for transport in a pure hydrogen pipeline. It is assumed that the hydrogen production facilities could be in either of the three states across the border, i.e., Michigan, Ohio, or Pennsylvania, which have CO_2 sequestration potential. The hydrogen production facility was modelled as being at a distance of 400 km from the steel plants in Ontario, as shown in the map of **Figure 5.6**.
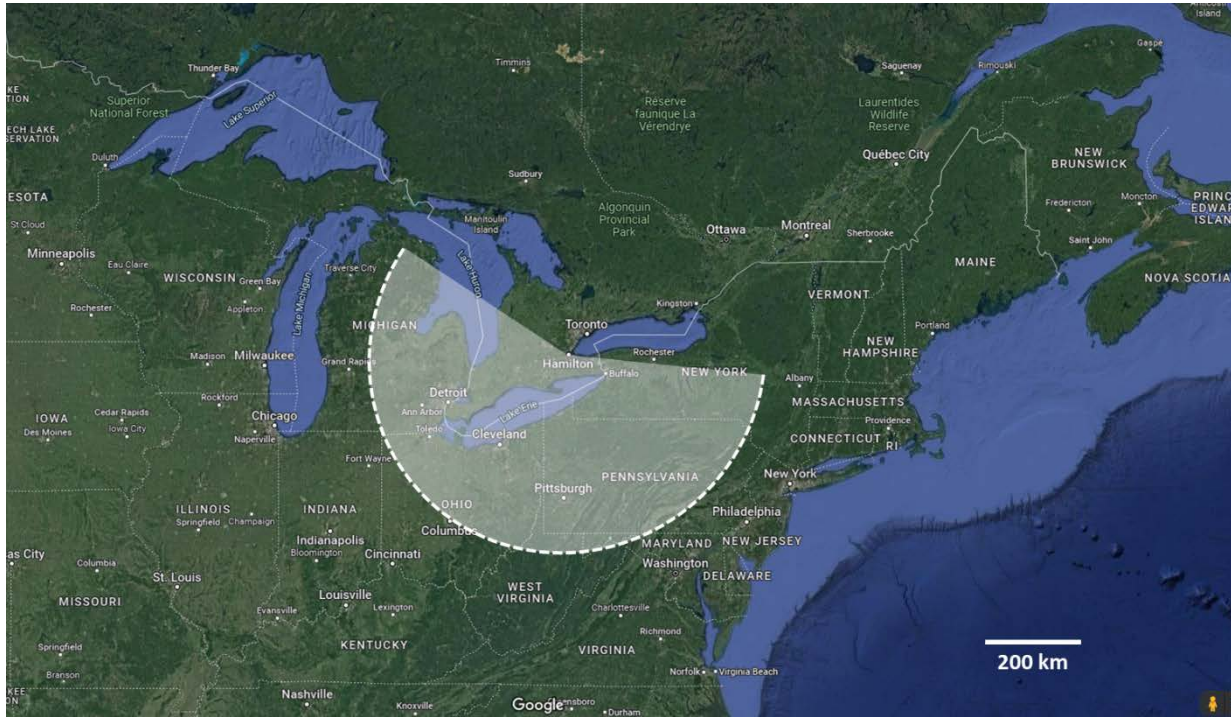
Figure 5.6. The white dotted line at the circumference of the shaded area shows potential areas for hydrogen production facilities, which are 400 km distance from Hamilton.

In our recent report on hydrogen transport using transmission pipelines [148], we demonstrated detailed gas flow and cost calculations of both transmission and distribution hydrogen pipelines. The ideal time for minimizing the cost of gas transport via a pipeline is during initial design and construction, where gas flow calculations, projected demand and other limitations are combined to optimize pipeline size, compressor units, flow rates, operating pressures etc. Using the methodology described in the report and the techno-economic parameters summarized in **Table 5.6** and **5.7**, we have calculated the cost of pipeline hydrogen transport from United states to Hamilton across a distance of 400 km.

Table 5.6. Summary of parameters used for gas flow calculations of the transmission hydrogen pipeline.

Parameter	Value	Notes/Reference
Total distance (km)	400	Assumption
Distance between compressors (km)	200	Assumption
Outlet gas velocity (m/s)	35	Assumption
Pipe roughness (mm)	0.0178	Based on private discussions.
Base Temperature (K)	288.71	[178,179]
Base pressure (kPa)	101	[178,179]
Flow temperature (K)	288.15	Assumption
Elevation difference (m)	100	Assumption
H_2 gas gravity	0.0696	[180]

Suction pressure of inlet compressor (bar)	20	Based on outlet pressure of SMR H_2 plant.
Discharge pressure of inlet and enroute compressor (bar)	70	= Inlet pressure of pipeline
η_{isen} (%)	80	[130]

To gauge the appropriate transmission pipeline sizes, gas flow calculations were conducted. **Figure 5.7** shows the maximum hydrogen transportation capacity and outlet pressure of a 400 km pipeline as a function of nominal pipe size (NPS), based on parameters used in **Table 5.6**, with one inlet compressor station and one enroute compressor station at a distance of 200 km. As expected, the capacity increases with larger pipe size, increasing from ~68 t_{H2}/day for a 6-inch pipeline to ~2100 t_{H2}/day for a 24-inch pipeline. This is co-related to the lower pressure drop in bigger pipelines with outlet pressures ranging from ~18.8 bars for a 6-inch pipeline to ~37 bars for a 24-inch pipeline.

Since pipelines cost millions of dollars and costs increase with pipe size, it is critical to select a pipe large enough to allow for an adequate supply of gas to flow through but not so large that it remains underutilized and drives up the capital investment and delivery costs. Ideally, a pipeline should be utilized at maximum capacity to lower the delivery cost of hydrogen. However, pipelines are designed with a higher capacity than the average flow rate to account for time variations in flow and allow for expansion. This leads to underutilized capital, which is modelled as an average capacity factor. The results of gas flow calculations indicate that a 16-inch pipeline is suitable to transport the potential hydrogen demand of 492 t_{H2}/day. A gas flow equivalent to 492 t_{H2}/day would represent a capacity factor of ~65% for a 16-inch pipeline with a maximum capacity of 756 t_{H2}/day, calculated using the parameters summarized in **Table 5.6**.

Table 5.7. Summary of parameters used for cost calculations of the transmission hydrogen pipeline.

Parameter	Value	Notes/Reference
Exchange rate	US$0.75/C$	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	C$0.11/kWh$_e$	Rate Alberta Industrial Electricity in Alberta; Source: NRCAN
Availability	90%	Assumed
Labor Rate (C$/hr)	49.6	Source: HDSAM
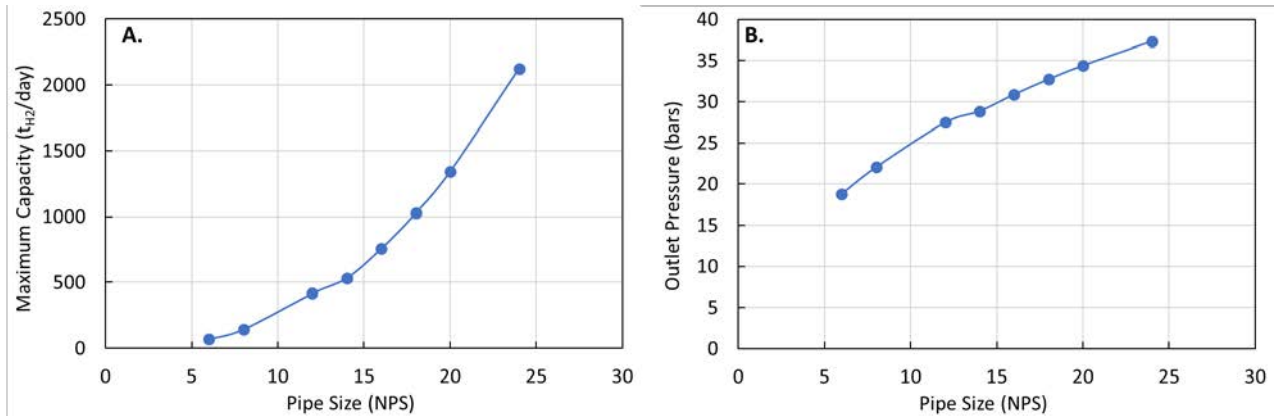
Figure 5.7. (A) Pipeline capacity (t_{H2}/day) and (B) Outlet pressure (bars) versus pipe size (NPS) for a 400 km pipeline with one inlet compressor and one enroute compressor.

To gauge the impact of demand on hydrogen pipeline costs, we analyzed the impact of the future H2DRI facility at ArcelorMittal working at different capacities, as shown in **Figure 5.8A**. The calculated hydrogen demand from the planned 2.5 Mt_{DRI} ArcelorMittal facility increases from 246 t_{H2}/day to 492 t_{H2}/day as the plant operates at 50% capacity versus 100% capacity. This directly impacts the pipeline capacity factor, which decreases transport costs from approximately C$1.7/$kg_{H2}$ to C$1.0/$kg_{H2}$. These costs include both pipeline and compression costs, with pipeline costs contributing approximately 80% and compression costs contributing 20%.

The delivered cost of hydrogen to the steel plants can be calculated by adding the hydrogen pipeline costs to the cost of hydrogen production, CO_2 capture, CO_2 transport and storage, as presented in section 4.2.1. We assume production from SMR plants at a natural gas price of C$4/$GJ_{NG}$ and an electricity price of C$0.1/kWh. Thereafter the hydrogen is transported via a 16-inch pure hydrogen pipeline. **Figure 5.8B** shows that the total delivered cost would be approximately C$3.1-4.0/$kg_{H2}$, depending on hydrogen demand from the H2 DRI-EAF steel facility. The highest contribution is from production costs (31-39%), followed by hydrogen pipeline costs (23-36%), CO_2 capture costs (20-24%), hydrogen compression (7-8%) and CO_2 transport and storage (5-6%).
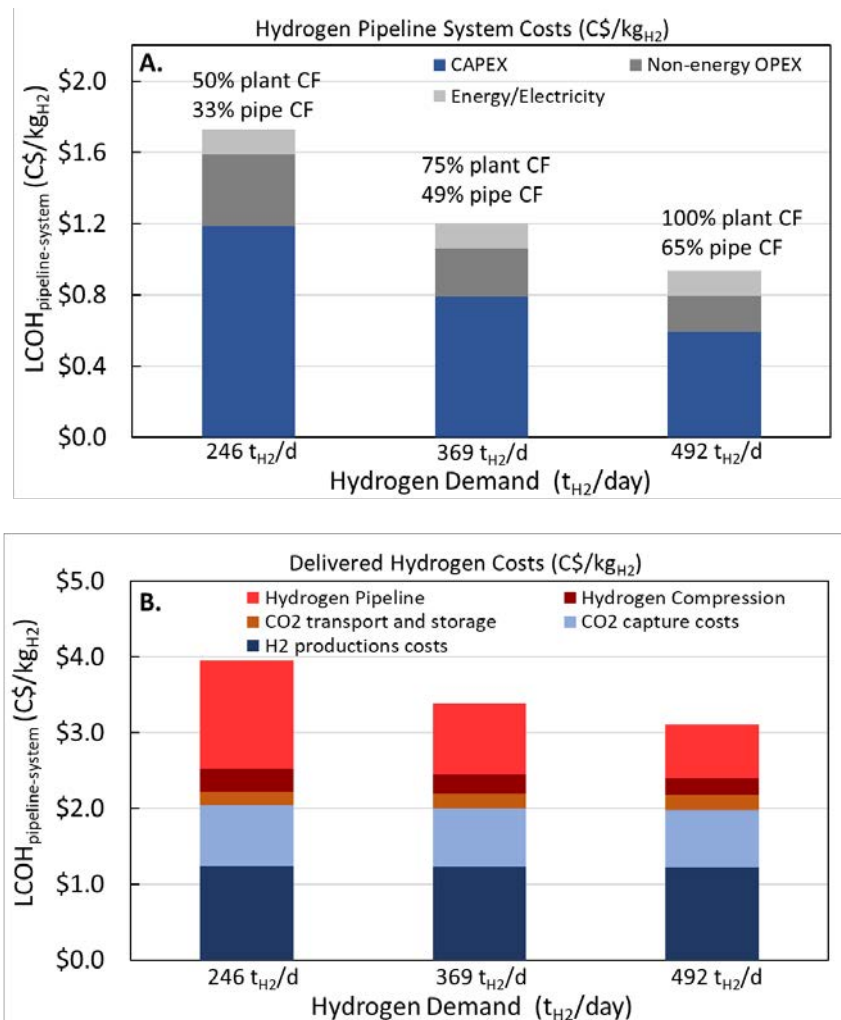
Figure 5.8. (A) LCOHpipe-system **(C$/kg**H2**) using a 16-inch pipeline as a function of capacity factor (%) or demand (t**H2**/day) from the H**2 **DRI-EAF steel plant. (B) Delivered hydrogen costs (C$/kg**H2**) from blue SMR plants to the H**2 **DRI-EAF facility at a distance of 400 km using a 16-inch pipeline and as a function of demand (t**H2**/day) from the H**2 **DRI-EAF steel plant.**

5.5 Steel Manufacturing and Hydrogen Cost Impacts

Whereas no manufacturing costs specific to Ontario or to the integrated steel plants are available in the public domain, approximate costs have been published for American and various other steel plants [181]. **Figure 5.9** indicates those costs by cost component. Iron ore and energy pricing increases led to a marked cost increase of one-third or more in 2021 after a 5% decrease in 2020. This is due mainly to a surge in iron ore and energy prices. For the U.S., this increase means that a tonne of steel cost about US$500 to produce in 2016, about US$600 in 2018 and US$750 in 2021. The report indicates plant-based costs of between US$750 and 860 per tonne of crude steel in 2021. Since 2021, when iron ore pricing increased to about US$225 per tonne, it has since come down nearly to pre-pandemic levels of about US$135 per tonne in

early 2023 [182]. This suggests that production costs may remain fairly stable in the longer term at a lower level of around US$600 per tonne for the U.S.

Source: This analysis by TransitionZero and GEI
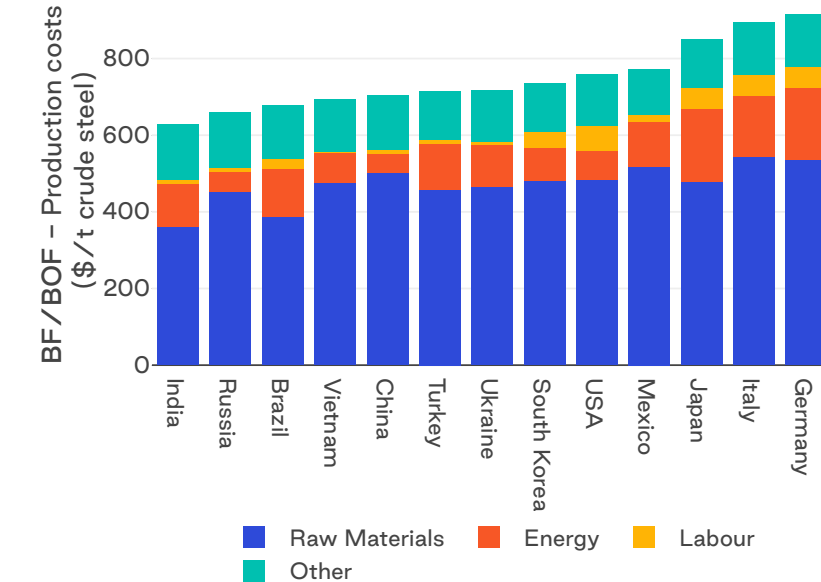
Figure 5.9. Steel Production Costs in 2021, in US$, by country

Energy costs are generally lower in the U.S. than in most other countries, and we will assume here that Canadian costs are very similar. If energy costs constitute about US$73 of the total in the U.S., this would be 12% of the total at a total cost of US$600 per tonne. A high-level estimate of steelmaking energy costs in Ontario is made in **Table 5.8**. The total energy cost of almost $100 per tonne of steel corresponds well to the U.S. cost of US$73 per tonne. The table does not consider that there is currently no performance standard for the DRI-EAF route. Theoretically, this means their natural gas use would be subject to the carbon tax, which would increase their fuel costs over what is shown in the table. It is assumed, however, that Ontario regulations for DRI-EAF will be developed over time and that a similar regime will apply as for the integrated route.

Table 5.8. Estimated energy costs per tonne of raw steel produced in Ontario from different routes, in C$

Pathway	Energy use	MJ*	Typical unit	$/unit	Cost
BF-BOF	Coke	12,500	0.35 t	$70/t	$25
	Natural gas	6,400	6.4 GJ	$5.5/GJ	$35
	Electricity	1,400	0.4 MWh	$126/MWh	$50
	Total				**$110**
DRI with NG	Carbon	400	0.01 t	$70/t	$0.9
	Natural gas	8,000	8.0 GJ	$5.5/GJ	$44
	Electricity	3,200	0.73 MWh	$126/MWh	$92
	Total				**$137**
DRI with H_2	Hydrogen	8,700	61 kg	$3/kg	$184
	Natural gas	1,500	1.5 GJ	$5.5/GJ	$8
	Electricity	3,200	0.73 MWh	$126/MWh	$92
	Total				**$284**

* Based on Section 3.5 and CSPA-provided energy data

This rough estimate indicates very similar energy costs for switching from blast furnace to DRI with natural gas, but costs increase strongly – about threefold – when moving to 100% hydrogen. This does not include re-heating furnaces, which would add another C$33 per tonne of steel if heated with hydrogen instead of natural gas. The price of electricity assumed is high, considering future increases due to substantial new capacities over the coming years to decarbonize and increase electricity use. The natural gas used for the H2-DRI case may also be replaced with additional hydrogen and biogenic carbon.

These indicative numbers, which are not representative of any specific facility, suggest that the steel production cost would increase from about C$800 to about C$1000 per tonne of crude steel or by about 25%. That premium presumes the use of blue hydrogen produced at scale; the use of green hydrogen would add substantially to this cost. This is a substantial increase that demands either a levelling of the playing field to remain competitive or clients that are willing to pay a corresponding premium for low-GHG steel.

6 STEEL INDUSTRY DECARBONIZATION AND THE NET-ZERO TRANSITION IN ONTARIO

6.1 The Scale of the Net-Zero Transition in Ontario

The government of Ontario has committed to reduce its greenhouse gas (GHG) emissions by 80% by 2050 [183], and if the province is to align with current federal policies, this commitment will need to be increased to net-zero emissions by 2050. Either way, the energy systems of the province will need to be transformed and shifted from relying on fossil carbon-based energy carriers to zero-emission energy carriers. Ontario already has an electrical grid with a very low GHG intensity (about 25 kg CO_2e/MWh), so it is well positioned for this transformation.

The steel industry does not exist in isolation from other parts of the energy system, and if all sectors are shifting towards zero-emission technologies, synergies could arise that would benefit the steel industry and vice-versa. This chapter explores this opportunity.

To understand what such a transformation would mean for the province, we conducted a detailed analysis of end-use sectors in Ontario in 2019, quantifying and characterizing the fuels and electricity consumed, the nature of the service provided, and the zero-emission alternatives capable of delivering a similar energy service. The analysis considered only the energy-using sector, including transportation, agriculture, residential and commercial buildings, and industry whose primary products are not electricity or fuels; therefore, electricity generation, oil and gas recovery, and petroleum refining were excluded.

Figure 6.1 shows that in 2019, Ontario showed an end-use energy demand of 2651 PJ/year, with 39% used in the building sector, 36% in transportation, 23% in industry and 2.4% in agriculture. Given a projected population growth for Ontario of about 36% between 2019 and 2050 [184], in the absence of efficiency improvements, total energy use could rise to about 3600 PJ/yr by 2050.

In this section of the report, we examine the current energy demand in each of these sectors and identify what we see as the most credible zero-emission energy carriers capable of fulfilling the province's energy needs. Five possible net-zero solutions were included:

a) **Electrification**, including electric vehicles, heat pumps for space and water heating and electrification of industrial processes. For this part of the study, we only calculate the increase in electricity demand brought about by the energy transition, not how that electricity would be provided, although it would need to be made with minimal or no GHG emissions. Possible sources include wind, solar, hydro, nuclear,

geothermal, or fossil fuels coupled to CCS. We do not analyze the physical constraints on the magnitude of low-GHG electricity to be produced and transported.

Secondary Energy Demand in Ontario (2019)
Total: 2651 PJ/yr
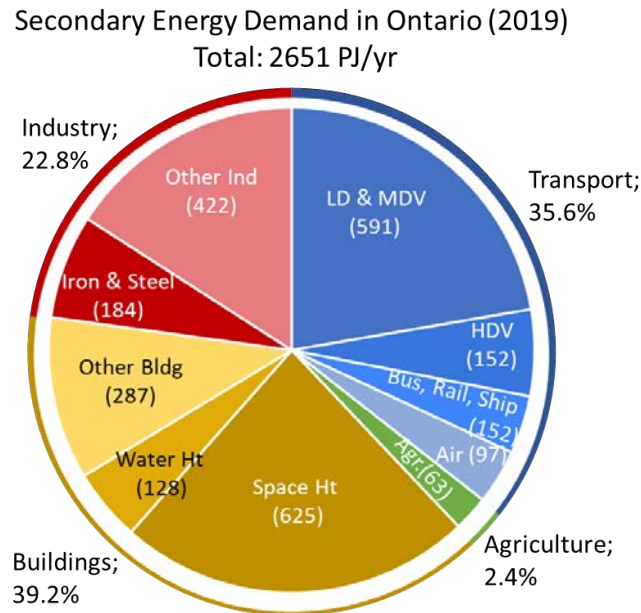
Figure 6.1. 2019 secondary energy demand in Ontario that excludes the use of energy by energy-producing industries such as power generation, oil and gas extraction or petroleum refineries

b) **Biomass and Biofuels,** where lignocellulosic biomass (e.g., wood) is burned for heat, and the biofuels include 'drop-in' fuels such as ethanol, biodiesel, biogas, as well as renewable gasoline, diesel, jet fuel or natural gas. The assumption is that the energy feedstocks can be produced and used with little or no net GHG emissions (i.e., they do not deplete biosphere carbon stocks). Our analysis recognizes that the availability of residual biobased feedstocks is limited, and the sustainable growth of dedicated energy crops and trees is not only expensive, but it can compete with food production and undermine biodiversity. Our analysis did not include recent evidence [185,186] showing that diverting residual biomass to energy use can have significant GHG impacts, nor the fact that biosphere carbon management is a key negative emission technology [187] that may be needed to remove residual emissions to actually achieve net-zero. These considerations would further constrain the use of biomass and biofuels as zero-emission solutions.

c) **Hydrogen and Ammonia** for use as a transportation or heating fuel. Very low GHG hydrogen could be produced from water electrolysis ('green' hydrogen) using low-GHG electricity (less than 100 kg CO_2e/MWh), or from the reforming of fossil fuels ('blue' or 'turquoise' hydrogen) where the by-product carbon is not released to the atmosphere. Leaked hydrogen is an indirect GHG [188], but related impacts have not been considered for the current study, assuming minimal leakage. For blue hydrogen production, geological sequestration capacity is needed. As discussed in Chapter 5, while Ontario has some potential for geological storage of CO_2 [189,190], the capacity is limited in the province compared to other regions in North America. However, it is possible for blue hydrogen to be produced in regions

that have the appropriate geology and the hydrogen pipelined to the province, as is currently done for natural gas and crude oil. We do not see any physical constraints on the magnitude of low-GHG hydrogen that could be produced and/or delivered to the province.

d) **Fossil Fuels with Carbon Capture and Storage.** Another net-zero solution is the continued use of fossil fuels combined with CCS. Given the limited size of this resource in Ontario, we have constrained its use to industrial sectors that have few other options, including cement and steel production. Petroleum refining is another sector that could use CCS, but as an energy producing sector, it is not considered here.

The choice of zero-emission energy carriers in the following sections assumes they are deployed at scale as part of a comprehensive industrial and energy strategy for the province. The scenario provided below does not arise from an incremental sector-by-sector model that chooses short-term, least-cost, low-carbon solutions. As discussed previously [191,192], we argue that such decision-making tools can lead to dead-end transition pathways and overlook lower-cost, system-level transitions that build on a shared public-private sector vision and regional strengths.

6.2 Transportation Energy Use in Ontario

In 2019, Ontario consumed 943 PJ_{HHV} in support of transportation [193], as shown in the pie chart at the center of **Figure 6.2.** Light-duty vehicles were the largest energy consumer (56%), followed by heavy-duty vehicles (16%), airplanes (10%), medium-duty vehicles (7%), and off-road vehicles (5%). Gasoline is the primary transport fuel for light-duty vehicles, while diesel is mainly used for buses, trucks, and rail. The remaining energy use is derived from jet fuel (planes) and heavy oil (marine), with minor contributions from electricity and natural gas.

Based on current and emerging technologies, and the needs of each sector, a judgement was made for the most likely zero-emission energy carrier/technology solution. The first step in the analysis defines the proportion of current energy use by subsector/fuel that is projected to be served by the zero-emission energy carrier and technology. This result is then combined with data on the relative efficiency of the zero-emission fuel alternative when compared with the incumbent internal combustion engine technology (**Table 6.1**) to calculate the PJ/yr of the zero-emission fuel used.

Light-duty vehicles (LDV, 528 PJ/yr): This sector includes cars (205 PJ/yr), passenger light trucks (241 PJ/yr), freight light trucks (81 PJ/yr) and motorcycles (1.9 PJ/yr) that drive an average of 17,252 km/veh/yr and where gasoline-ethanol fuel accounts for 98% of 2019 fuel demand. In the transition to zero-emission fuels, we assumed that 9% of 2019 fuel use is provided by biofuels, 5% by hydrogen (taxi fleets and LDVs that are purchased for long-distance transport) and 86% by electricity (transition to BEVs). Because of the efficiency improvements of BEVs and HFCEVs compared to ICEVs (**Table 6.1**), a net zero energy system for the 2019 LDV sector would use only 29% of 2019 energy use by the sector (Outer doughnut chart, **Figure 6.2**).
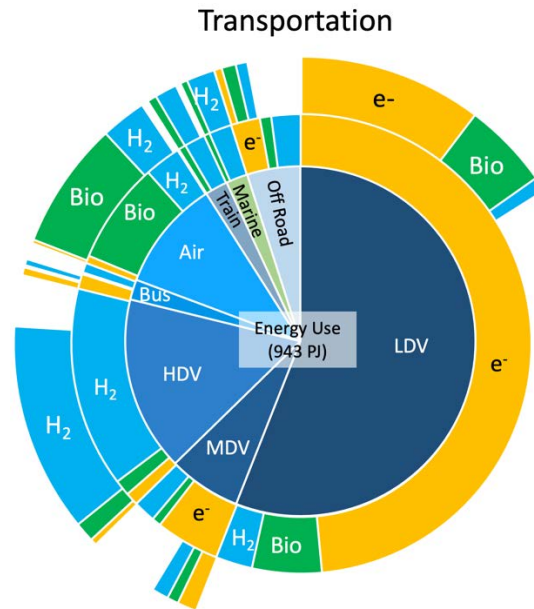
Figure 6.2. Energy use for transportation in Ontario by vehicle type in 2019 (inner circle). Projected zero-emission energy source to displace existing energy services (smaller donut); projected energy required by the zero-emission alternatives (larger donut)

Table 6.1. Examples of relative efficiency calculations for zero emission technologies /energy carriers compared with fossil fuel (FF) technology for use in transport.

A	B	C	D	E	F	G
Zero Emission Option			Incumbent			Relative Efficiency
Energy Carrier	Technology	Efficiency	Technology	Fuel	Efficiency J kin/ J FF	
Grid power	LD&MD BEV	0.76 J kin/J e	LD&MD ICE	Gasoline	0.16	0.21 J e/J FF
Grid power	MD BEV	0.76 J kin/J e	MD ICE	Diesel	0.25	0.33 J e/J FF
Grid power	MD BEV	0.76 J kin/J e	MD ICE	NG	0.20	0.26 J e/J FF
Grid power	HD BEV	0.76 J kin/J e	HD ICE	Diesel	0.35	0.46 J e/J FF
Grid power	BEV	0.76 J kin/J e	Airplane	jet Fuel	0.30	0.39 J e/J FF
hydrogen	LD&MD HFCEV	0.50 J kin/J H2	LD&MD ICE	Gasoline	0.16	0.32 J H2/J FF
hydrogen	MD HFCEV	0.50 J kin/J H3	MD ICE	Diesel	0.25	0.50 J H2/J FF
hydrogen	MD HFCEV	0.50 J kin/J H4	MD ICE	NG	0.20	0.40 J H2/J FF
hydrogen	HD HFCEV	0.47 J kin/J H5	HD ICE	Diesel	0.40	0.85 J H2/J FF
hydrogen	Airplane HFCEV	0.50 J kin/J H6	Airplane ICE	jet Fuel	0.30	0.60 J H2/J FF
ren gasoline	LD&MD ICE	0.16 J kin/J Ren	LD&MD ICE	Gasoline	0.16	1.00 J Ren/J FF
ren diesel	MD ICE	0.25 J kin/J Ren	MD ICE	Diesel	0.25	1.00 J Ren/J FF
ren NG	MD ICE	0.20 J kin/J Ren	MD ICE	NG	0.20	1.00 J Ren/J FF
ren diesel	HD ICE	0.40 J kin/J Ren	HD ICE	Diesel	0.40	1.00 J Ren/J FF
ren jet fuel	Airplane ICE	0.30 J kin/J Ren	Airplane ICE	jet Fuel	0.30	1.00 J Ren/J FF

Note: Values in columns B and F are obtained from the literature. Column G is calculated as column F ÷ column B

Medium duty vehicles (MDV, 63 PJ/yr): These MDVs are used mostly for freight transport up to 15t gross vehicle weight (GVW) and drive an average of 21,014 VKT/veh/yr, and fuel demand is split between gasoline/ethanol (55%) and diesel/biodiesel (44%). In the transition to zero-emission fuels, we assumed 9% of 2019 fuel use is provided by biofuels, 23% by hydrogen (HFCEVs used for larger, longer-haul vehicles averaging 60,000 VKT/veh/yr), while the remaining 67% is provided by electricity (BEVs). The net-zero energy use for this sector would only be 40% of the 2019 energy use by the sector.

Heavy duty vehicles (HDV, 152 PJ/yr): These are 15+ t HDVs used for freight transport that uses diesel fuel and drive an average of 99,058 VKT/veh/yr. Many of the trucks in this class are purchased for long-haul routes (200,000+ VKT/veh/yr) and used for 3-5 years before being sold to carriers focused on short-haul applications. In the transition to zero-emission fuels, we assumed that 7% of 2019 fuel use is provided by biofuels, 87% by hydrogen (HFCEVs), and the remaining 6% is supported by electricity (BEVs used solely for shorter-haul routes). The long-haul, rapid refuelling needs in the HDV sector removes most of the market for BEVs.

Buses (18 PJ/yr): While school buses were assumed to be almost 100% BEV, the long travel distances, heavy loads, and rapid refuelling needs identified HFCEV as the technology of choice for the intercity/tour bus market. For transit fleets, there is a trend toward BEVs for the smaller buses, shorter routes and HFCE for the larger buses, longer routes and larger fleets. In the transition to zero-emission fuels, we estimated 6% of 2019 fuel use would be provided by biofuels, 37% by hydrogen and the remaining 56% by electricity.

Airplanes (97 PJ/yr): Discussions with industry regarding the challenges of the net-zero energy transition for this sector led us to allocate 70% use to biofuels, 25% to hydrogen (HFCE planes targeting domestic routes) and the remaining 5% to electricity (battery-electric planes).

Rail locomotives (20 PJ/yr): While passenger and commuter trains could use electricity, such trains account for only 2% of fuel used by the rail sector. Following discussions with the sector, we allocated 25% of the 2019 fuel used to be supported by biofuels, 70% by hydrogen and the remaining 5% to electricity. CP Rail is already building HFCE freight locomotives [194].

Marine (19 PJ/yr): In 2019, fuel use in this sector is dominated by heavy fuel oil, presumably used by large ships moving through the Great Lakes. While electrification could be used with ferries, their material for the province of Ontario. Biofuels are an obvious solution, but limitations in feedstock supply convinced us to set biofuels at 20%, with ammonia (from hydrogen) making up the balance of 80% fuel energy displacement.

Off-road vehicles (46 PJ/yr): This sector includes construction and airport vehicles, as well as off-road recreational vehicles. Full electrification can be challenging, given the distance to grid power and the challenges with recharging. We propose that 2019 fuel demand will be supported by a mix of net-zero energy carriers, with 16% allocated to biofuels, 42% to hydrogen and 42% to electricity.

Total Transport (943 PJ/yr): Based on our assumptions and analysis, the transition to more efficient zero-emission carriers would result in energy savings of 485 PJ/yr for the transport sector, which is approximately 51% of current energy use. Given the assumptions and calculations that result from this analysis, we project that a transition to net zero for Ontario's 2019 energy use for transportation would have the following characteristics:

- Low-GHG electricity would address 58% of energy use and require an additional 33.4 TWhr/yr of power generation in Ontario, equivalent to a 22% increase in the provincial grid.

- Sustainably grown biofuels would address 15% of energy use, requiring 2.7 billion l/year, which could require up to 13 Mt/year of biomass feedstock to produce.

- Low-GHG hydrogen would address 27% of energy use, requiring 3648 t_{H2}/day.

6.3 Agricultural Energy use in Ontario

Agriculture accounts for only a small portion (2.4%) of secondary energy demand in Ontario. The 63 PJ_{HHV}/yr demand can be divided into motive and non-motive uses, as shown by the pie chart (**Figure 6.3**). The motive use of energy is around 25 PJ_{HHV}/yr, primarily driven by diesel (65%) and gasoline (33%). On the other hand, non-motive energy use consumes 38 PJ_{HHV}/yr, mainly supplied by natural gas (61%) and electricity (25%).

Figure 6.3. Energy use for agriculture in Ontario by fuel type in 2019 (inner circle). Projected zero-emission energy source to displace existing energy services (smaller donut). Projected energy required by the zero-emission alternatives (larger donut).

Not surprisingly, energy use in the agricultural sector is highly seasonal, with heavy use in the spring (planting) and fall (harvest). When many of the most energy-intense vehicles are used in agriculture (seeders, combines, etc.), they are often needed continuously for long (20 hr+) days. Consequently, experts we have consulted in the agricultural sector are concerned about whether BEVs could meet their motive needs (recharging time and cost of recharging infrastructure) and whether the rural grids could handle the large seasonal demand in energy for drying crops and recharging vehicles etc. On the other hand, farms are often

well positioned to support renewables (especially wind and solar generation) that could provide an economic advantage for shifting to electrification. In the scenario presented in **Figure 6.3** (inner doughnut), we propose a fairly large role for electrification in the shift of the agricultural sector to zero-emission fuels:

<u>Motive applications:</u> In the transition to zero-emission fuels, we assume 5% of 2019 fuel use for motive applications is provided by biofuels, 46% by hydrogen (or ammonia) and 49% by electricity. Ammonia is also a fertilizer; many farmers are skilled in handling this toxic chemical. Companies are starting to produce ammonia-fueled [195] and hydrogen-fueled [196] tractors.

<u>Non-motive applications</u>: For non-motive applications, we assume 28% of 2019 fuel energy demand to be supplied by hydrogen and 72% by electricity.

These projections may be overly optimistic for electricity use in the agricultural sector unless there are significant technological improvements. Nevertheless, the scenario projects that a transition to net zero for Ontario's 2019 energy use for agriculture would have the following characteristics:

- Low-GHG electricity would address 63% of energy use and require an additional 3.9 TWhr/yr of power generation in Ontario, equivalent to a 2.6% increase in the provincial grid.

- Sustainably grown biofuels would address 2% of energy use that could require up to 0.16 Mt/year of biomass feedstock to produce.

- Low-GHG hydrogen would address 35% of energy use, requiring 353 t_{H2}/day.

6.4   Building Energy Use in Ontario

Before analyzing the energy demand for buildings in Ontario, it is important to discuss the zero-emission options for building heating. Electrification via heat pumps is considered the most efficient option to decarbonize heating for buildings. The efficiency of heat pumps is reported as their coefficient of performance (COP), which is the ratio of thermal energy delivered by the heat pump and its input electrical energy and is a function of outside temperatures and indoor thermostat settings. The COP for air-source heat pumps varies from over 300% to less than 180% when the outdoor temperature decreases from +10°C to -20°C (**Figure 6.4**). On the other hand, pure hydrogen furnaces are expected to behave similarly to gas furnaces, which are 90-95% efficient, irrespective of the outdoor temperature.
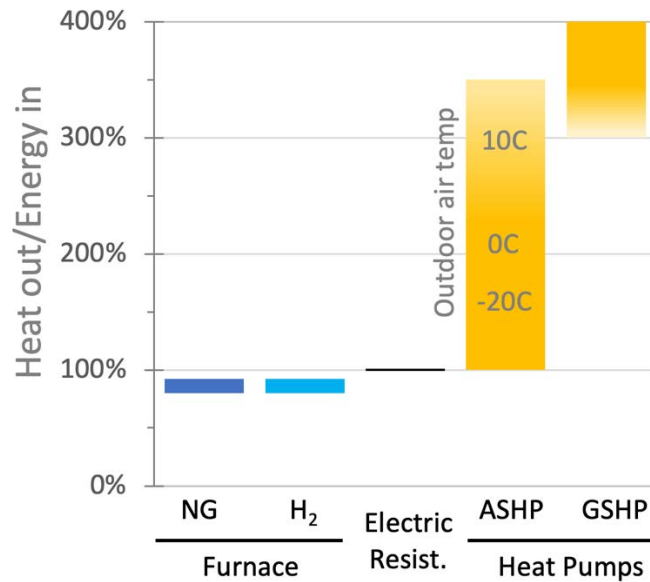
Figure 6.4. Comparison of the efficiency of space heating technologies.

Source: Heat pump efficiencies from [197]. ASHP, air-source heat pump, GSHP, ground-source heat pump.
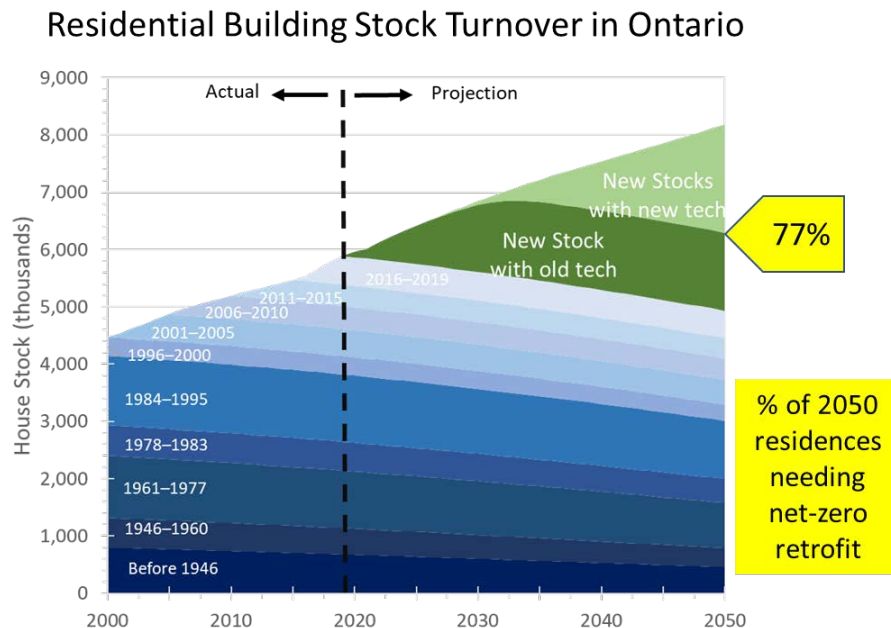
Figure 6.5. Stock turnover analysis of residential buildings in Ontario.

Source: Calculated from data in the Comprehensive Energy Use Database [193], future projection of space heating technologies assumed 'S-curve' deployment of new zero-emission buildings with a 50% market share achieved in 2032.

It is clear that electric heat pumps will dominate space heating. This will require significant changes and costs to the buildings (inside and outside) to upgrade the main electrical panel and possibly wiring as well. While these changes are relatively easier and cheaper to apply to newly built buildings, retrofitting older houses

Hydrogen and the Decarbonization of Steel Production in Canada

will be much more complex and costly. A stock turnover analysis of residential buildings in Ontario is presented in **Figure 6.5,** based on parallel research underway by the Transition Accelerator. The data reveals that by 2050, approximately 77% of the residential building stock in Ontario will require retrofits. The cost and disturbance associated with such a transition will favour the transition to hydrogen as a space heating solution for retrofits, especially in larger buildings and densely populated regions. If existing residences are converted to heat pumps, they will likely be air-source rather than ground-source heat pumps that require expensive boreholes to be drilled.

Based on the cold winters in Ontario and the current COP of air-source heat pumps, our preliminary analysis shows that if low-GHG hydrogen can be made available at less than C\$3/kg$_{H2}$, hydrogen is likely to be a lower-cost solution than electric air-source heat pumps for retrofits. Furthermore, it is important to note that the electrification of heating demand will require significant upgrades to the grid infrastructure. Therefore, we envision hydrogen to play a supporting role in providing energy for space and water heating for buildings.
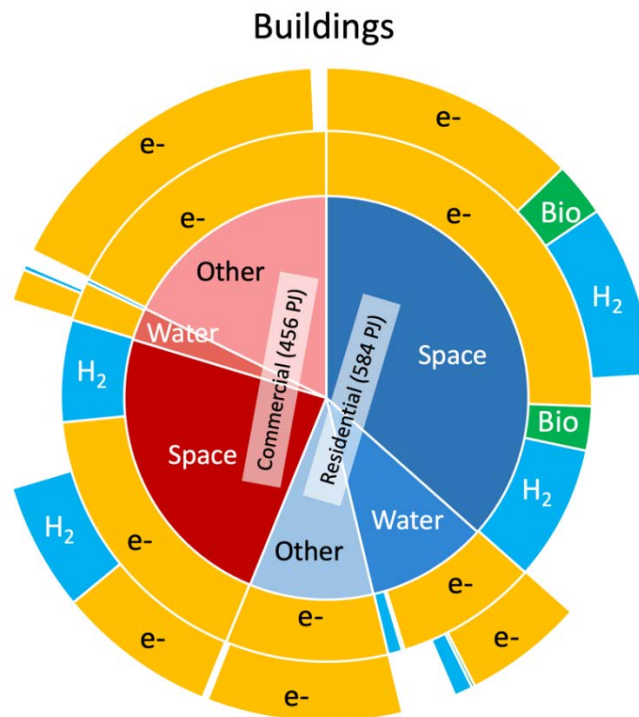
Figure 6.6. Energy use for buildings in Ontario by use case in 2019 (the inner circle). Projected zero-emission energy source to displace existing energy services (smaller donut). Projected energy required by the zero-emission alternatives (larger donut).

Ontario's energy use for space and water heating in 2019 was 1040 PJ$_{HHV}$, as shown in **Figure 6.6**, with 56% (584 PJ$_{HHV}$/yr) and 46% (456 PJ$_{HHV}$/yr) consumption coming from residential and commercial buildings, respectively. As a first approximation for the demand for zero-emission alternatives, 2019 fuel use was allocated to three different zero-emission alternatives without considering population or economic growth.

Electricity was considered as the fuel of choice for supplying the majority of space heating demand and almost all of the water heating demand. Hydrogen was considered to provide a supporting role for the reasons discussed above. Biofuels were considered to play a minor role in providing space heating for remote communities. The proportion per subsector, as shown by the smaller donut chart in **Figure 6.6**, can be summarized as follows:

- Residential space heating: 70% electricity; 7% biofuels; 23% hydrogen
- Residential water heating: 90% electricity; 1.5% biofuels; 8.5% hydrogen
- Residential (other energy use): 100% electricity; 0% biofuels; 0% hydrogen
- Commercial space heating: 74% electricity; 0% biofuels; 26% hydrogen
- Commercial water heating: 91% electricity; 0% biofuels; 9% hydrogen
- Commercial (other energy use) 100% electricity; 0% biofuels; 0% hydrogen

The use of electric heat pumps would result in an improvement in relative efficiency. The projected energy required by zero-emission energy carriers is shown by the larger donut chart in **Figure 6.6**. A total of 767 PJ_{HHV}/yr would be required resulting in energy savings of 273 PJ_{HHV}/yr (26% of current energy demand). Given the assumptions and calculations that result from this analysis, we project that a transition to net zero for Ontario's 2019 energy use for buildings would have the following characteristics:

- Low GHG electricity would address 82% of energy use and require an additional 61.3 TWhr/yr of power generation in Ontario, equivalent to a 40% increase in the provincial grid.

- Sustainably grown biofuels would address 2.5% of energy use, that could require up to 1.8 Mt/year of biomass feedstock to produce.

- Low GHG hydrogen would address 15.5% of energy use, requiring an additional 3221 t_{H2}/day to be produced.

6.5 Industrial End Use in Ontario

In 2019, approximately 605.4 PJ_{HHV} of energy was used by industries in Ontario in 2019. This excludes the energy used by energy-producing industries such as power generation, oil and gas extraction or petroleum refineries. The largest industrial consumer of energy and fossil reduction agents in Ontario is the steel industry (30%), followed by pulp and paper (12%), chemicals (11%), mining (6%), construction (6%), cement (4%) and forestry (1%). The balance of energy demand is lumped into multiple other industry types, as shown in the pie chart of **Figure 6.7.** The dominant fuels currently used in these different industries are summarized below:

- ☐ Construction: Diesel (86%)
- ☐ Pulp and Paper: Biomass (48%) and Natural Gas (29%)
- ☐ Cement: Coal (61%)
- ☐ Chemicals: Natural Gas (67%) and Electricity (28%)
- ☐ Iron and Steel: Coal (60%) and Natural Gas (31%), as fuels and for iron reduction
- ☐ Forestry: Diesel (100%)
- ☐ Mining: Electricity (52%) and Diesel (28%)

☐   Other manufacturing: Natural Gas (56%) and Electricity (34%)
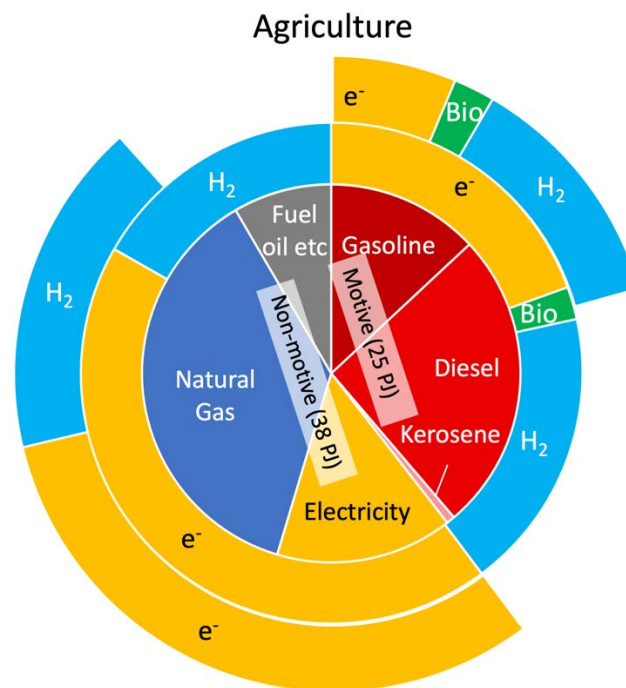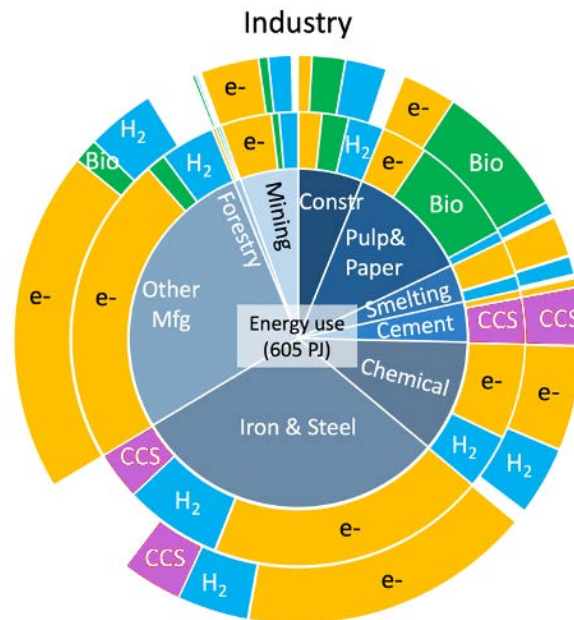

Figure 6.7. Energy use for the industry in Ontario by use case in 2019 (inner circle). Projected zero-emission energy source to displace existing energy services (smaller donut). Projected energy required by the zero-emission alternatives (larger donut).

These fuels are used for various purposes, such as providing heat, power generation, transportation, and driving machinery; their use as chemical reduction agents (rather than combustion as fuel) is also included here. As a first approximation of demand for zero-emission alternatives, the 2019 demand was allocated to four different options, i.e., electricity (yellow), biofuels (green), hydrogen (blue) and fossil fuel plus CCS (purple). This analysis does not consider population or economic growth. The proportion allocated to each subsector were made based on based on perceived needs of the sector. The proportion per subsector, as shown by the smaller donut chart in **Figure 6.7**, can be summarized as follows:

☐   **Construction:** 27% electricity; 31% biofuels; 42% hydrogen; 0% fossil plus CCS. Since construction is often carried out 'off grid', we allocated a larger role to hydrogen or ammonia, where it would be used to displace diesel fuel and propane.

☐   **Pulp and Paper:** 28% electricity; 66% biofuels; 7% hydrogen; 0% fossil plus CCS. These companies have ready access to biomass, which was seen as the most compelling energy resource. Hydrogen was projected to have a minor role in replacing diesel for some applications.

☐   **Cement:** 14% electricity; 0% biofuels; 1% hydrogen; 85% fossil plus CCS. The large process emissions associated with cement production mean that decarbonizing the fuel source does not achieve near net zero. Therefore, for this sector, we argue that CCS is the only credible solution.

☐   **Chemicals:** 63% electricity; 0% biofuels; 37% hydrogen; 0% fossil plus CCS. While electricity is expected to dominate as the net-zero solution, reducing power demand in this sector creates a need for hydrogen.

☐ **Iron and Steel:** 66% electricity; 0% biofuels;[4] 23% hydrogen; 11% fossil plus CCS. Based on this study, we assumed that part of the sector will move to EAF of recycled steel, the part will incorporate CCS with existing fossil fuel use, and part will use hydrogen as the energy carrier.

☐ **Forestry:** 40% electricity; 30% biofuels; 30% hydrogen; 0% fossil plus CCS. Hydrogen or ammonia was seen as the most appropriate zero-emission fuel source to support forest harvest equipment and hauling operations. However, electricity and biofuels would play a more important role.

☐ **Mining:** 66% electricity; 10% biofuels; 24% hydrogen; 0% fossil plus CCS. For below-ground mining operations, electricity was assumed to dominate. Hydrogen or ammonia's role was seen as the ideal zero-emission fuel to support large mining vehicles and provide off-grid heat and power.

This means that 61% of Ontario's current energy demand for industry would be displaced by electricity, 12% by biofuels, 24% by hydrogen and 3% with the use of fossil fuels with CCS. Using the relative efficiency factors, the projected energy required from zero-emission energy carriers is shown by the larger donut chart in **Figure 6.7**.

Given the assumptions and calculations that result from this analysis, we project that a transition to net zero for Ontario's 2019 energy use for the industry would have the following characteristics:

- Low-GHG electricity would address 60.5% of energy use and require an additional 50.23 TWh/yr of power generation in Ontario, equivalent to a 33% increase in the provincial grid.

- Sustainably grown biofuels would address 12% of energy use and could require up to 5.5 Mt/year of biomass feedstock to produce.

- Low-GHG hydrogen (or ammonia) would address 21% of energy use, requiring an additional 2062 t_{H_2}/day to be produced.

- The balance of energy use would be supported by fossil fuel use coupled with CCUS, accounting for 6.5%.

6.6 Hydrogen Demand for Energy Production

Two additional hydrogen users in Ontario are the petroleum refining industry and power generation. These sectors are not included among the energy-using sectors discussed in the previous sections. However, their hydrogen demand would be substantial and add further economies of scale to hydrogen production and demand:

- According to a recent report to support the creation of a Sarnia Hydrogen Hub [198],over 410 t H_2/day is currently produced and consumed per year in Sarnia as feedstock for refining, chemicals, and fertilizer production. This could be replaced with low-GHG hydrogen to help decarbonize these industries.

- Another opportunity for hydrogen use lies in replacing natural gas for peaking power. This option has been addressed in the IESO report on decarbonizing Ontario's electricity grid. At 12 TWh of

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[4] Other assumptions are also possible, especially as the Ontario steel industry is also exploring the use of biomass-based reduction agents.

peak electricity made from Ontario peaking power plants and assuming a 35% efficiency for single-cycle power plants, this will require 123 million gigajoules of hydrogen, equivalent to 2384 t H_2/d.

6.7 Energy Demand in a Net-Zero Future for Ontario

The energy demand analysis for zero-emission carriers in Ontario as presented in the previous section reveals the scale of the challenge ahead. Reaching net-zero emissions by 2050 will require transformative changes in the way we generate and consume energy, move people and goods, construct urban spaces, organize the agriculture system, and operate industries. The current energy demand in Ontario and the calculated total energy demand for zero-emission energy carriers are summarized in **Table 6.2**.

Our analysis reveals that to reach net-zero emissions, Ontario will need to generate 287 TWh of low-GHG electricity per year, 9284 tonnes of low-GHG hydrogen per day, 20 million tonnes of dry biomass and sequester over 3 million tonnes of CO_2 every year, based on current energy demand. This will require Ontario to almost double its current electricity production of 151 TWh per year [165] and produce more low-GHG hydrogen than the entire country's current production capacity (8200 t_{H2}/day) [89]. Adding in merchant hydrogen demand from petroleum and other industries in the Sarnia region and anticipated needs for peaking power with hydrogen by 2050, this increases to over 12,000 tonnes of hydrogen per day.

In addition to the challenge of producing large amounts of low-GHG energy, core infrastructure for transporting the energy to end users, such as the electrical grid, hydrogen pipelines, and CO_2 pipelines, will have to be expanded or installed. This infrastructure is capital-intensive and will require significant investment (billions of C$). The small demand for zero-emission carriers in an early market and an uncertain future make it expensive and financially risky to invest in such infrastructure today. Hydrogen pipelines are expensive. Yet, as demonstrated in Chapter 4, they represent the lowest-cost way of delivering hydrogen at scale. The lack of infrastructure adds to the cost of zero-emission energy carriers such as hydrogen for early adopters and any incremental hydrogen use as part of a decarbonization strategy.

Ontario's steel industry is a key economic sector, contributing billions of dollars to the economy and supporting thousands of jobs and over 10,000 indirect jobs across the country. As summarized in Chapter 5, the large volumes of steel produced mean that a direct transition to the H2-DRI process would not only help decarbonize the sector but also results in significant hydrogen demand creation that contributes to the business case for building hydrogen and/or CO_2 pipelines in southwestern Ontario. If these pipelines can be used to serve hydrogen demand from other sectors, such as heavy-duty transport and space heating, it can further lower the costs of hydrogen delivery.

As a first approximation, we have estimated the demand for net-zero energy carriers in southwestern Ontario comprising of Toronto, Hamilton, Kitchener-Cambridge-Waterloo, London, St Catherines-Niagara, Windsor, Oshawa, Barrie, Guelph, and Brantford, where 70% of the province's population resides. Based on this, southwestern Ontario will need to generate 200 TWh of low-GHG electricity per year, 6462 tonnes of low-GHG hydrogen per day, 14 million tonnes of dry biomass and sequester over 3 million tonnes of CO_2 every year to drive our current energy demand.

Assuming population growth of 36% between 2019 and 2050, mid-century demand in southwestern Ontario could be 272 TWh /yr of electricity, 8800 tH$_2$/d and 19 Mt/yr of dry biomass.

Table 6.2. Summary of 2019 secondary energy use in Ontario (Columns A to E) and the zero-emission energy system designed to deliver similar energy services (Columns F to N)

Note that the calculations for 2019 only include end-use demand, not the energy used to recover and refine oil and gas or the energy used in electricity generation. Two key energy producers were added to column K to better gauge demand through 2050. Also, the zero-emission energy system is based on Ontario's 2019 energy system and does not consider economic or population growth between 2019 and 2050, when the Canadian government has committed to net zero.

		A	B	C	D	E	F	G	H	I	J	K	L	M	N
		2019 Energy use					Zero Emission Energy System Delivering Similar Energy Services								
	Sector	Electricity		Bioenrgy / fuels	Fossil Fuels	Total	Low GHG Electricity		Bioenergy/fuels		Hydrogen & Ammonia		Fossil Fuels with 90% CCS		TOTAL
		PJ/yr	TWhr/yr	PJ/yr	PJ/yr	PJ/yr	PJ/yr	TWh/yr	PJ/yr	Mt /yr	PJ/yr	t H_2/d	PJ/yr	MT CO_2/yr	PJ/yr
Non-energy Producing	Transportation	1.5	0.4	45.9	896	943	122	33.9	102	12.6	189	3647			412
	Agriculture	9.47	2.6		53	63	23.5	6.53	1.30	0.16	18.2	353			43
	Residential	158	43.9	28.7	397	584	295	82.0	29.61	1.83	98.0	1895			423
	Commercial	192	53.3		264	456	275	76.5			68.6	1326			344
	Industry (non-energy)	135	37.6	42	428	605	316	87.9	89.4	5.55	107	2063	40.8	3.28	553
	Non-Energy TTL:	**496**	**138**	**117**	**2038**	**2651**	**1032**	**287**	**222**	**20**	**480**	**9284**	**40.8**	**3.28**	**1775**
	SW Ont. only*	**346**	**96**	**81**	**1419**	**1846**	**719**	**200**	**155**	**14**	**334**	**6462**	**40.8**	**3.28**	**1248**
Energy Producing	Refineries											410			
	Peak Power (IESO)											2384			
	Energy TTL:											**2794**			
Ontario Total												**12078**			

* For all but CCS estimates, values calculated as 70% of all Ontario values based on proportion of 2021 population living in Toronto (6.2M), Hamilton (0.78M), Kitchener-Cambridge-Waterloo (0.58M), London (0.54M), St Catherines-Niagara (0.43M), Windsor (0.42M), Oshawa (0.42M), Barrie (0.21M), Guelph (0.17M) and Brantford (0.14M) when the provincial population was 14.2M (https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=9810000101).

6.8 Hydrogen Supply Costs at Scale

In section 5.4, we calculated the delivered cost of hydrogen to the announced 2.5 Mt_{DRI} per year facility by ArcelorMittal Dofasco. Even at 100% operating capacity, the scale of demand leads to pipeline delivery costs of around C$1/$kg_{H2}$. If part of southwestern Ontario's net-zero demand for hydrogen (>6462 t_{H2}/day) can be supplied via the same pipeline system, it can significantly lower hydrogen pipeline costs, as shown in **Figure 6.8**. Hydrogen demand in excess of 1400 t_{H2}/day will lead to very low hydrogen pipeline costs, ≤C$0.5/$kg_{H2}$.
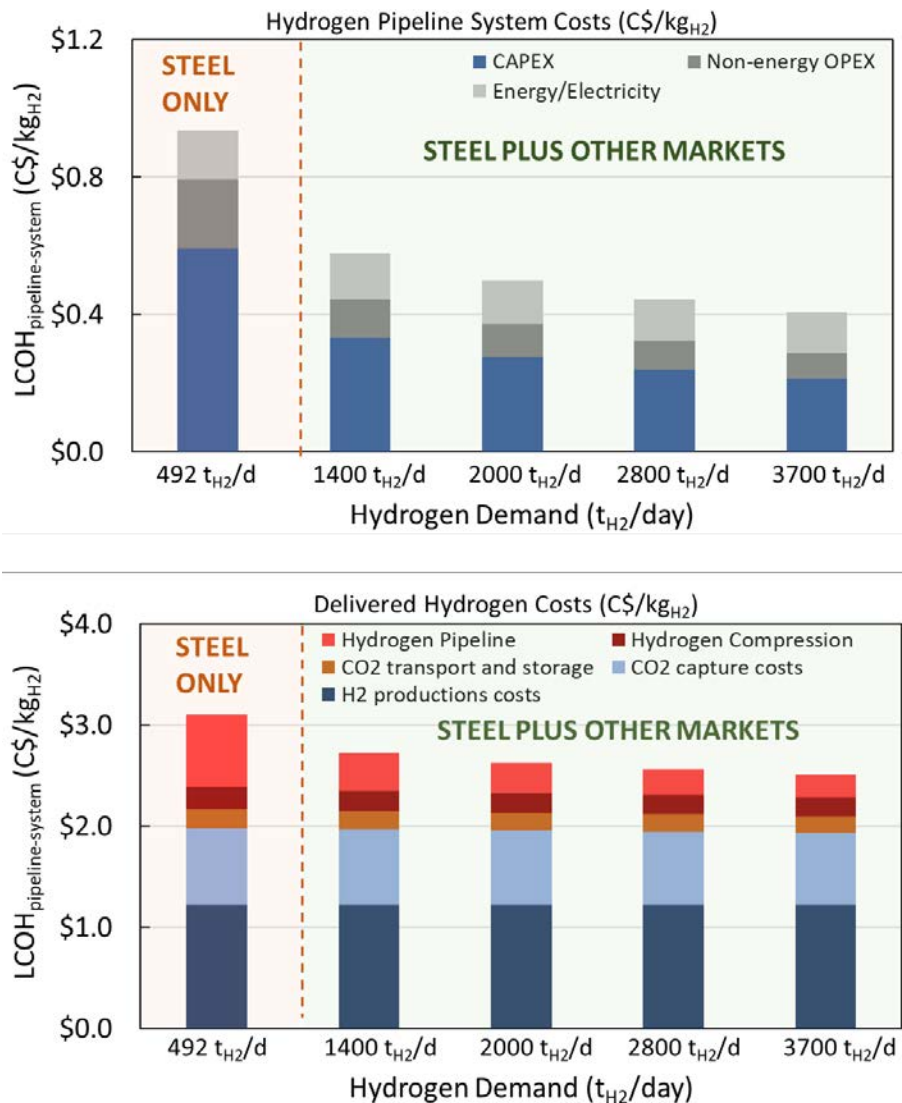
Figure 6.8. (A) LCOH_pipe-system (C$/kg_{H2}) as a function of hydrogen demand (t_{H2}/day) in SW Ontario. (B) Delivered hydrogen costs (C$/kg_{H2}) from blue SMR plants to SW Ontario at a distance of 400 km as a function of demand (t_{H2}/day).

At such scales, the delivered cost of hydrogen to Southern Ontario would be ≤C$2.7/kg$_{H2}$ (**Figure 6.8**), opening opportunities for its adoption and use in various sectors such as heavy-duty transport, agriculture, space heating and other industrial uses. This would go a long way in meeting the energy demand in a net-zero future.

Moving forward, our analysis leads us to conclude that the steel industry in Ontario can act as an anchor tenant (**Figure 6.9**) that helps create demand for zero-emission energy carriers and help build the core infrastructure needed for a net-zero energy system. This would have far-reaching consequences for the decarbonization of various sectors, such as transport, space heating, chemicals, and accelerate the transition to a net-zero future.
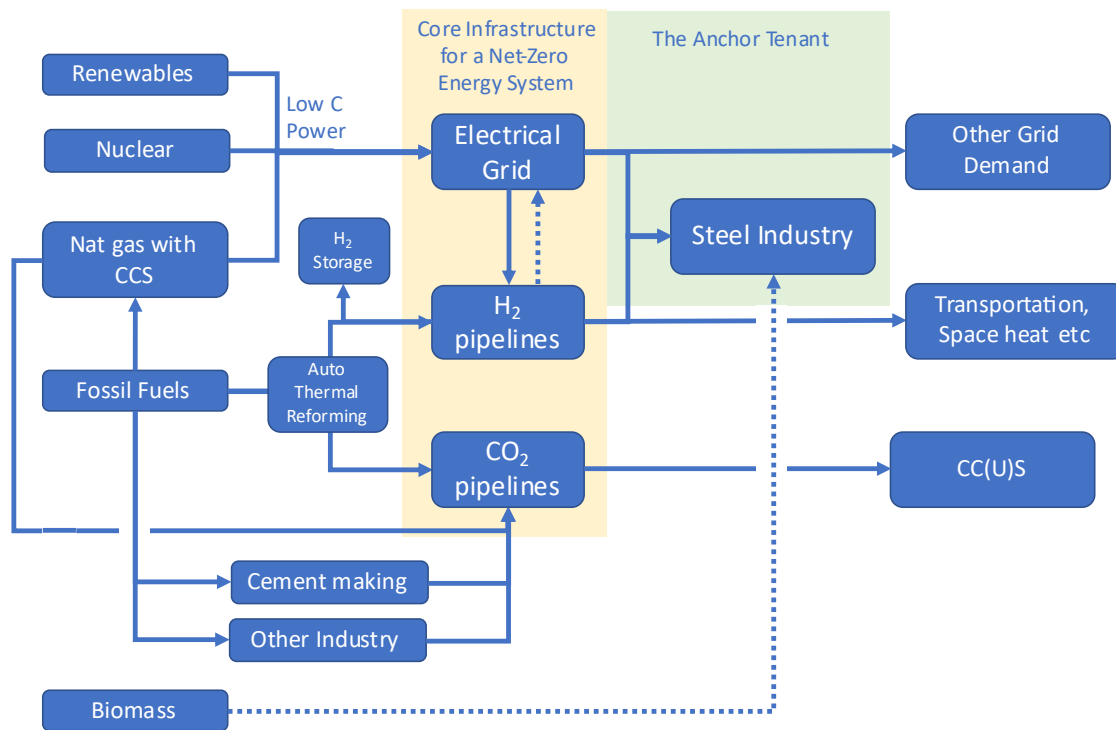
Figure 6.9. Schematic showing a future net-zero energy system where the steel industry can act as an anchor tenant to deploy core infrastructure.

7 CONCLUSIONS

Canada and dozens of other nations have committed to net-zero GHG emissions by 2050. The scale and challenge of the transition are unprecedented and will require transformative changes in different sectors and systems we use for social provisioning. Nowhere is the challenge more evident than for the Canadian steel industry, which employs more than 23,000 Canadians and contributes to the economy through a wide range of activities, including the use of steel in sectors such as energy, construction, and automotive manufacturing [199].

Currently, Canadian production of steel generates about 15 million tonnes of CO_2e per year in GHG emissions, equivalent to 2% of the country's GHG emissions in 2019 [1]. The majority of these emissions are from the use of coke and coal in integrated plants in Ontario. However, to align itself with Canada's net-zero targets, the CSPA released its Climate Call to Action in 2020 and adopted the aspirational net-zero emissions by 2050 [3]. To date, the steel industry, government, and private investment will enable technological change that is estimated to reduce the steel industry's absolute emissions by over 45% by 2030 while additional projects and investments continue to come forward. As confirmed by international benchmarking, Canada and its North American partners produce some of the lowest-GHG steel in the world. The industry is committed to finding solutions to continue to reduce the footprint of its operations and provide an opportunity for other sectors to leverage the steel sector's decarbonization efforts over the next thirty years.

In this report, we have assessed various pathways for decarbonizing the integrated steel industry in Canada. While an increased reliance on secondary steel production that uses scrap steel recycled in EAF plants powered by low-GHG electricity can help to reduce GHG emissions, meeting societal needs for steel requires that some of the steel is produced from iron ore [2].

The current technology for primary steel production in Canada and around the world involves the use of coal and coke in BF-BOF steelmaking, a technology known for high energy use (18 to 20 GJ/t steel, **Figure 7.1A**) and high GHG emissions (1.5 to 1.8 tCO_2/t_{Steel} **Figure 7.1B**). Replacing coke made from coal with coke made from biomass is an option currently under investigation by the Canadian steel industry. Incorporating post-combustion CCS is reported to reduce emissions by 43 to 60% [200], while also increasing energy demand. The CCS technology is mature, although, to our knowledge, no commercial application has been deployed in the steel industry.

The development of technologies such as oxyfuel combustion in oxy-blast furnaces and top gas recycling is promising for CO_2 capture with lower energy penalty and coke consumption but will require significant changes to the design and operation of the steel-making process. Other technologies, such as calcium looping, are also being pursued for carbon capture [201].

One of the alternatives is that primary steel can be produced via the DRI process. The DRI process has the potential to achieve substantial reductions in GHG emissions in the primary production of steel. If NG fuels the DRI process, energy use per tonne of steel can be reduced by 33 to 39% (**Figure 7.1A**), and direct (Scope 1) emissions reduced by up to 73% (**Figure 7.1B**). Upstream (Scope 2) emissions associated with natural gas production or electricity generation also contribute to the lifecycle emissions associated with steel production. However, initiatives are underway in those sectors to reduce emissions [202,203], which would be helpful in reducing the environmental footprint of the steel industry.

To achieve even greater GHG emission reductions, the DRI process can be fueled with hydrogen rather than natural gas, and direct (Scope 1) emissions could be reduced by 95% compared to the BF-BOF technology (**Figure 7.1B**). Since 85% to 90% of the energy input for H_2 DRI-EAF comes from hydrogen and electricity (**Figure 7.1A**), the lifecycle performance of this technology relies on access to low-GHG production of hydrogen and electricity. Assuming a grid carbon intensity in Ontario of 25 kg CO_2/MWh and a lifecycle carbon intensity for hydrogen production of 20 kg CO_2/GJ_{H2}, the lifecycle emissions from steel production using BF-BOF would be reduced by 80 to 90%.
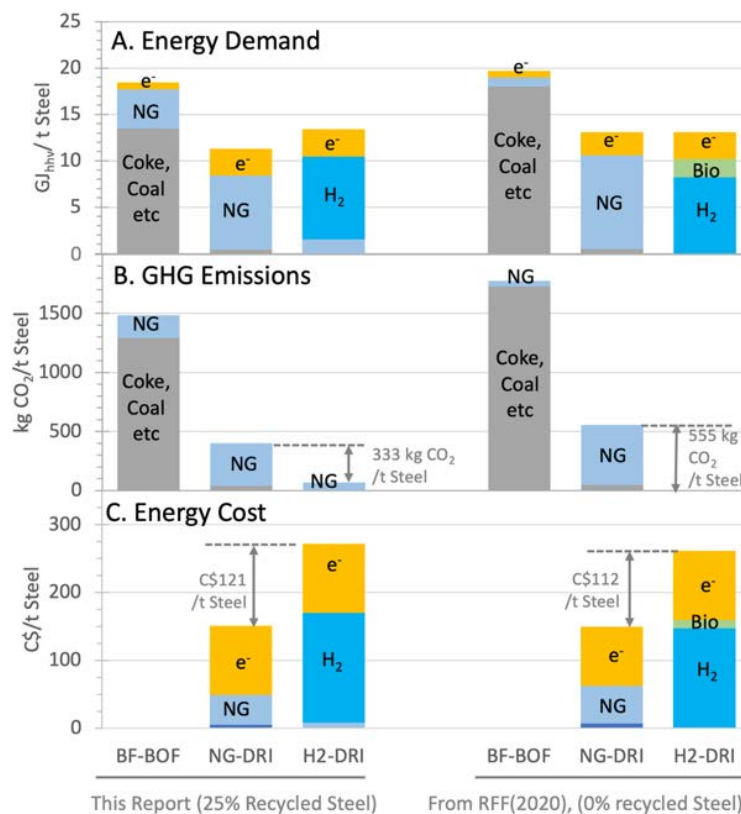
Figure 7.1. Comparison of two reports and three primary steel-making processes for Energy Demand (A), GHG Emissions (B) and Energy Cost (C). For RFF(2020), see reference [204].

Note: The upstream (Scope 2) emissions associated with natural gas recovery, as well as hydrogen, biomass and electricity production, are not included. For the energy cost estimates, delivered energy costs are assumed: natural gas in Hamilton (C$5.5/GJ), natural gas in the USA (C$4/GJ), hydrogen (C$2.50/kg), biomass (C$100/dry tonne) and electricity (C$126/MWh).

Cost and Feasibility of Using Green Hydrogen: Assuming that the delivered (low carbon) electricity price is C\$126/MWh [205], the cost of electricity to support the H2-DRI process is about C\$102/t Steel. If electricity at this price were used to generate the 'green' hydrogen by water electrolysis, the electricity demand would be four times larger than for direct electricity use for steel production, and the cost of hydrogen would be about \$7.46/kg H_2 (C\$53/GJ H_2). At almost ten times the cost of natural gas for the NG-DRI process, this is not a credible solution.

If off-site, lower-cost, low-GHG electricity (C\$30/MWh from future large-scale wind and solar deployment) were used to make green hydrogen, the cost would drop to C\$2.46/kg H_2, but approximately C\$1/kg H_2 would be needed to store and pipeline the gas to the plant. The resulting price of C\$3.46/kg H_2 (C\$24/GJ) would still be 4.4 times the natural gas cost for the NG-DRI. This is closer to credible, but one must also consider the scale of demand.

For a production of 2.5 million tonnes of H2-DRI steel per year in the Hamilton region [9], 492 t H_2/d is needed. If made electrolytically, 9.3 TWh/yr of low-GHG electricity would be required, equivalent to a 6.2% increase in the current size of the Ontario grid. If this electricity were made using wind power (assuming an average capacity factor of 38%), 2809 MW of wind capacity would be needed, equivalent to a 50% increase of the installed wind capacity in the province.

Another possibility is to use nuclear power to make the low carbon electricity, but it would be difficult to meet a price point of C\$30-40/MWh electricity with nuclear power. None of these cost estimates incorporate tax credit provisions for clean hydrogen production, such as those announced in the most recent federal budget [206].

Cost of Blue Hydrogen Production and Delivery: One of the challenges associated with blue hydrogen production is that it can only be done cost-effectively at large volumes, mostly because of the scale needed to capture and store the byproduct CO_2. Autothermal reforming of natural gas to make 492 t H_2/d can be done at low cost (C\$2.25/kg assuming a NG cost of C\$5.50/GJ), and the CO_2 needing subsurface storage (~1.6 Mt CO_2/yr) meets the criteria for scale to keep the costs down. Unfortunately, most of the geology of Ontario is not compatible with geological storage, but two sites (under Lake Erie and the southern portion of Lake Huron) seem to have porous rocks that are sufficiently deep (>800m) to store CO_2 [189]. At 1.6 Mt CO_2/yr, there are more than 100 years of storage capacity, and the province is working to change its laws to allow for CCS [207]. However, there is likely to be competition from other industry available in the province.

Another possibility is to make blue hydrogen where the geology is better suited to CCS, and the cost of NG is lower and pipeline the hydrogen to the Hamilton region. Michigan, Ohio, and Pennsylvania meet such criteria and are within 400 km of Hamilton. The cost of pipelining 492 t_{H_2}/day over 400 km would be about C1\$/kg_{H_2}. Assuming a natural gas price of C\$4/GJ_{NG} at the point of hydrogen production, the delivered cost of blue hydrogen would be about C\$3.1/kg_{H_2} (C\$22/GJ_{H_2}), equivalent to four times the NG cost.

To further reduce the costs and risks associated with low-GHG hydrogen supply to the Hamilton steel industry, it would be useful for the steel industry to position itself as an anchor tenant in a larger, province-wide hydrogen strategy serving the transportation, agriculture, as well as space and industrial heating.

Assuming a 36% growth in population and energy service demand by 2050, we estimate hydrogen demand in South-Western Ontario to be about 8800 tH_2/day or 18 times the demand for hydrogen by the ArcelorMittal Dofasco project in Hamilton.

Significant reductions in pipelining costs can be realized by increasing the volume of hydrogen moving into the province. If hydrogen transport increased from 492 t_{H2}/d to 3700 t_{H2}/d, the cost of the pipeline system would decline from C$1/kg $_{H2}$ to C$0.4/kg$_{H2}$. That would reduce the delivered cost of hydrogen from C$3.10-2.50/kg$_{H2}$ (C$18/GJ$_{H2}$), equivalent to 3.2 times the NG cost.

The cost estimates provided here do not consider Canadian or US government incentives for CCUS or low-GHG hydrogen production that are currently in place or being deployed. In Canada, the investment tax credit for clean hydrogen announced in the recent Budget 2023 should provide some cost reduction for hydrogen producers and distributors, making hydrogen more affordable for large industrial users [208].

The US Inflation Reduction Act [209] has strong incentives for low-GHG hydrogen production in the USA and does not restrict the export of this hydrogen to other nations, so that could create an opportunity for the Province of Ontario and the steel industry.

BOX 1	US HYDROGEN TAX CREDIT

The Inflation Reduction Act of 2022 creates a tax credit that would pay clean hydrogen producers up to $3 per kilogram (adjusted for inflation). The size of the tax credits available to US clean hydrogen producers depends on the well-to-gate GHG emissions of each project and related employment creation. The basic tax credit rate is set at US$0.60/kg. At less than 0.45 kg of lifecycle CO_2e emissions per kg, hydrogen would receive 100% of the credit, reduced to 33.4% for up to 1.5 $kgCO_2e$ per kilogram, 25% up to 2.5 kg and 20% up to 4 kg. The tax credit is multiplied by five when labourers and mechanics employed by contractors and subcontractors in the construction of a facility are paid wages at rates "not less than the prevailing rates for construction, alteration, or repair of a similar character in the locality in which such facility is located as most recently determined by the Secretary of Labor".

Blue hydrogen projects would be ineligible for hydrogen tax credits if they already receive federal tax credits for carbon capture and storage — but green hydrogen projects would also be allowed to receive renewable energy tax credits valued at $30/MWh in addition to the hydrogen ones [210].

Hydrogen cost per tonne CO_2 abated: Assuming cost estimates for the large-scale production of blue hydrogen in the USA and pipelining it to Canada, the incremental cost of shifting to H2-DRI from NG-DRI ranges from C$112 to C$121/t Steel (**Figure 7.1C**). Considering only the reduction of Scope 1 emissions, the effective cost per tonne CO_2 abated ranges from C$201-364/t CO_2 (**Figure 7.1 B and C**). While this is a high cost, it will probably be challenging to reduce it much further.

Other options for hydrogen production with low GHG emissions include methane pyrolysis and hydrogen production from residual biomass or municipal solid waste streams. While these technologies are still in the early stages of commercialization, we recommend keeping a close eye on these technologies as there may be important advances in the coming decade.

Addressing the increased costs of low-GHG steel production. Making steel with minimal or no GHG emissions comes with significant costs and various technological challenges. Options to address the cost differential will be critical for the steel industry to decarbonize. We recommend that industry and government work together to address this important issue by exploring solutions in the following ways:

1. **Reinvest revenue created from carbon pricing in the steelmaking sector** into steel decarbonization technologies that are on a transition pathway to net zero. In 2022, carbon taxes in Canada were $50/t CO_2e and have been scheduled to increase by $15/t CO_2e per year to 2030, when they will reach $170/t CO_2e. This study showed that the fuel cost to transition from NG DRI-EAF to H2 DRI-EAF is likely to be more than $200/t CO_2. It is worth noting that the Independent Electricity System Operator (IESO) in Ontario has done this calculation for electricity generation and estimated that decarbonize decarbonizing the electric grid by 2035 would require a carbon price of about $245/t CO_2e [211]. Through the use of border carbon adjustments, companies that produce and use low-GHG steel can be rewarded, while the higher emitters can pay a higher cost.

2. **Understand the impact of Canadian and US decarbonization policies on the cost of low-GHG hydrogen production.** In recent years, numerous policies and programs have been set up by the Canadian and US governments to incentivize the production of low-GHG hydrogen as a zero-emission fuel. In the US, these include the 45Q Tax credit [212] and the more recent Inflation Reduction Act Hydrogen production tax credit [213]. There seem to be no constraints in those incentives benefiting Canadian industry.

   Canada has its own CCS tax credit system, and the 2023 budget noted that CCS projects will be backstopped by "contracts for difference", These contracts would guarantee predictability on the value of the carbon sequestered, thereby de-risking these major projects. Canada also has announced a clean hydrogen investment tax credit that has potential to improve the competitiveness of green hydrogen production and, potentially, blue hydrogen [206,214]. While details of these programs are still being developed, they have the potential to accelerate the use of hydrogen for steel production in Canada.

3. **Monitor the progress of innovations in low-GHG hydrogen production.** Technologies could be deployed in the steel sector without the need for CCS related to hydrogen production. These include natural gas pyrolysis to hydrogen and carbon black [215], and biomass (or municipal solid waste) to hydrogen production [125]. While these technologies are not currently being deployed at a scale and with the reliability needed by the steel industry, they are progressing rapidly and could make an important contribution in the future.

4. **Work with the region and province to develop and deploy a regional strategy around hydrogen.** The economics of hydrogen production, storage and transport are significantly improved with scale. The result will not only be lowered costs, but lower risk, and the opportunity to attract public support and government investment. As discussed in Chapter 6, the steel industry is not alone in needing low-cost hydrogen fuel to transition to net-zero emission energy systems. Other sectors include heavy freight (road, rail, ships), space and industrial heating, and even peak power generation. The steel industry has the potential to be an anchor tenant in this larger shift to

hydrogen. This would best be done by supporting the creation of a hydrogen hub and associated hydrogen corridors in the Hamilton region.

5. **Build a premium market for low-GHG steel.** Government demand for steel (e.g., for construction) could require low-GHG steel, thereby helping to create a market demand for a steel with a gradually lower GHG intensity over time. There is tremendous opportunity for green procurement in the net-zero transition while enhancing competitiveness. An example of this is apparent in the auto manufacturing sector. Volvo Group, in collaboration with SSAB, are working on the development, serial production and commercialization of the world's first vehicles made of fossil-free steel [216]. Identifying a standard for low-GHG steel and then using that standard to develop a Canadian or North American brand would be a valuable starting point in building this new market. Considering green attributes in policy and purchasing decisions could support domestic industry and ensure a level playing field on carbon costs (i.e., border carbon measures, procurement policies, etc.).

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