Emission Mitigation in the Global Steel Industry: Representing CCS and Hydrogen Options in Integrated Assessment Modeling

Kali Benavides[a], Angelo Gurgel[a], Jennifer Morris[a], Bryan Mignone[b], Bryan Chapman[b], Haroon Kheshgi[c], Howard Herzog[a], Sergey Paltsev[a,*]

[a]*Massachusetts Institute of Technology, 77 Massachusetts Ave, Cambridge, MA 02139, USA*
[b]*ExxonMobil Technology and Engineering Company, 1545 Route 22 East, Annandale, NJ 08801, USA*
[c]*University of Illinois at Urbana-Champaign, 1301 Green Street, Urbana, IL 61801, USA*

Abstract

We conduct a techno-economic assessment of two low-emissions steel production technologies and evaluate their deployment in emissions mitigation scenarios utilizing the MIT Economic Projection and Policy Analysis (EPPA) model. The two technologies are steelmaking equipped with carbon capture and storage (CCS) and hydrogen-based steelmaking. Our technoeconomic analysis based on the current state of technologies found that the steelmaking equipped with carbon capture and storage increased costs ~7% relative to the conventional steel technology. The hydrogen-based steelmaking increased the costs by ~18% when utilizing *Blue* hydrogen and ~77% when using *Green* hydrogen. The exact pathways for hydrogen production in different world regions and CCS and hydrogen deployment in steelmaking are highly speculative at this point, but actions in the forms of research and development (R&D), technology demonstration, technology transfers, infrastructure development and policy incentives could speed up the transition to a low-emitting steelmaking industry. Our findings can be used to help decision-makers assess various decarbonization options and design economically efficient pathways to reduce emissions in the steel industry and other hard-to-abate sectors. Our cost evaluation can also be used for other energy-economic and integrated assessment models to provide insights on future decarbonization pathways.

Keywords: carbon capture; hydrogen; steel production; decarbonization; integrated assessment.

1. Introduction

Steel production is a major contributor to the overall emissions from sectors that are hard to decarbonize [1]. All assessed scenarios that lead to the international goal of limiting the global temperature rise to below 2 degrees Celsius relative to the pre-industrial temperature have deep reductions in emissions from every major sector [2]. In addition to near-term energy-efficiency and electrification measures, other decarbonization options, including low-carbon intensity hydrogen and carbon capture and storage (CCS), could help to achieve deep emission reductions. Our contribution to the literature is in explicit exploration of CCS deployment and hydrogen supply and use in the global steel industry.

In this study we enhance the global multi-region multi-sector MIT Economic Projection and Policy Analysis (EPPA) model [3,4] to capture the representation of inter-sectoral linkages, demand responses, competition between technologies, and substitution possibilities among inputs in iron and steel production and other sectors of the economy. We start with a consistent assessment of hydrogen production costs, including steam methane reforming with CCS,

* Corresponding author. Tel.: +1-617-253-0514, *E-mail address:* paltsev@mit.edu

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autothermal reforming with CCS, and polymer electrolyte membrane (PEM) hydrogen production (see Section 3 for a description of colors for hydrogen production pathways). We consider cases where electricity is generated by a dedicated renewable source (such as solar or wind) or taken from the existing grid in a particular world region. Currently, *Green* hydrogen options are more expensive in comparison to other pathways. In emission mitigation scenarios, we explore how the grid is decarbonized over time in different regions. We explore trajectories for cost reduction in both hydrogen and steel production (each with and without CCS) and we connect our study to our recent analysis of regional carbon storage availability [5] and cost of CO_2 transport and storage [6]. In this study, we focus on deployment of CCS and use of hydrogen in steelmaking. We compare our cost assessment with existing studies, such as IEA [7,8], The Energy and Resource Institute (TERI) [9] and others.

The paper is organized in the following way. In Section 2 we briefly describe traditional and advanced steel production pathways. Due to our focus on hydrogen, in Section 3 we discuss hydrogen production pathways. Section 4 presents our evaluation of costs for hydrogen-based and CCS-based steelmaking and hydrogen production. In Section 5 we apply the EPPA model to provide illustrative scenarios for low-emission steelmaking. Section 6 concludes.

2. Steel Production Pathways

Steelmaking can be divided into two major production pathways: blast furnace-basic oxygen furnace (BF-BOF) and direct reduced iron-electric arc furnace (DRI-EAF) [10-12]. In the BF-BOF route, iron ore, coke, and limestone are fed to a blast furnace (BF), where hot air passes from the bottom to the top, and the air ignites the coke, which produces additional heat and carbon monoxide (CO) gas. The high heat melts the materials, and the CO gas reacts with the iron ore's oxygen to make CO_2. The hot reduced metal flows to the bottom and is transported to the basic oxygen furnace (BOF), where oxygen is added to eliminate carbon from the hot liquid metal. In the DRI-EAF route, oxygen is removed from iron ore using a reducing agent such as natural gas or coal. But different reducing agents, feedstocks, and furnaces could be utilized for direct reduction. Direct reduced iron (DRI) is the end-product, which is converted to steel in an electric arc furnace (EAF). Carbon electrodes in the EAF are utilized to provide the necessary energy. The EAF can also be applied for various scraps (recycled steel) [11-12]. Both routes require raw materials preparation before the process as well as finishing to convert to the final steel products. A key part of the finishing process is hot rolling which is common to all the production pathways included in this technoeconomic analysis [8, 44]. Hot rolling is when the crude steel is reheated and pressed to reduce the thickness [45]. The hot rolled steel is then typically transported as coils or sheets to undergo further finishing to form the final steel product [45]. After the hot rolling step there are additional finishing processes that are specific to the end use of the steel [8].

Annual global crude steel production was about 2,000 million metric tonnes (Mt) in 2021, with China producing about half of the world steel [10]. Ten countries of the world (China, India, Japan, USA, Russia, Korea, Turkey, Germany, Brazil and Iran, produce about 83% of global steel. Globally, 70% of steel is made by the BF-BOF route, thanks in large part to its 90% market share in China. The other major steel producing countries in Asia also mostly rely on BF-BOF while in USA 70% of steel is produced by the DRI-EAF route. In the EU, the situation is more balanced 60% BF-BOF /40% DRI-EAF [10].

The transition to a low-carbon economy would require a portfolio of steel-making technologies [14]. Among the shorter-term options for emission reductions are an increase in energy efficiency, increase in recycled steel scrap, and replacement of coal with natural gas in the DRI process [12]. Several options are feasible in the longer-term: deployment of CCS; advanced low-carbon processes (such as the HIsarna process [8]), which are emission-reducing and also attractive for CCS; use of hydrogen for high temperature heat and/or the reducing agent in DRI; further increases in use of scrap; and enhancing resource efficiency (increasing durability, materials substitution in construction, etc.) [14]. Several studies provide a detailed description of the challenges and opportunities associated with low-emission steelmaking options [7-9, 11-12]. In this paper we focus on the cost assessment for CCS-based and hydrogen-based steelmaking.

3. Hydrogen Production Pathways

While currently the majority of hydrogen is produced from fossil fuels by steam methane reforming of natural gas or coal gasification, there are numerous other pathways for hydrogen production. These pathways are often distinguished from one another using a “color” label. Even though such coloring scheme oversimplifies the much more diverse variety of processes, we summarize it here because of its popularity with policy makers and industry experts.

The major hydrogen production pathway, steam methane reforming of natural gas, is referred to as *Grey* hydrogen [18]. The coal gasification route is referred to as *Brown* hydrogen [18]. If during these process CCS is applied to capture most of the CO_2 emissions, then it is called *Blue* hydrogen [18]. Hydrogen produced by electrolysis of water, using electricity from renewable sources such as wind or solar [13] is referred to as *Green* hydrogen [18]. If hydrogen is produced by electrolysis using grid electricity rather than dedicated renewable energy, then it is referred to as *Yellow* hydrogen [43]. If the electricity grid were eventually dominated by renewable energy technologies in the future, *Green* and *Yellow* pathways would eventually converge.

In terms of other major pathways, *Pink* hydrogen is produced by electrolysis using nuclear power, and *Turquoise* hydrogen is produced by methane pyrolysis, where solid carbon is produced instead of CO_2 gas [43]. Hydrogen also can be produced with biomass-based processes, such as biomass gasification or fermentation, but these processes currently do not have any assigned and agreed upon “color”. In this paper, we will focus on the costs for *Grey, Blue, Yellow*, and *Green* hydrogen production pathways and their use for steelmaking.

4. Cost Assessment for Low-Emission Steelmaking

4.1. Levelized Cost Calculations for Steel

We start our assessment by calculating the levelized costs of steel for three different production pathways: conventional DRI-EAF, DRI-EAF with CCS and Hydrogen DRI-EAF. The ratio of the levelized cost of the advanced steelmaking process to the levelized cost of the conventional DRI-EAF is utilized in the EPPA model as a markup value. The markup approach [15] that represents the cost of advanced technology relative to the cost of traditional technology is used in the EPPA model for assessing the economic competition between traditional and advanced steelmaking. If the markup is greater than one, advanced technology is not economical unless supported by other means, such as subsidies, standards, or requirements. The natural gas-based DRI-EAF production cost is used to determine the markups for the other steel production pathways. The cost shares determined by the levelized cost calculations are also utilized in the EPPA model to determine the inputs for each production pathway.

We include the iron making, steel making, and hot rolling processes in our assessment. We exclude the upstream processes of raw materials extraction and processing (like iron ore mining, agglomeration and pelletizing) because in the integrated assessment model these processes are included in the mining sector. For the levelized cost calculations, the iron and steel plant is modelled with an annual capacity of 2 Mtpa of hot rolled steel with a capacity factor of 90%. In Appendix A, we list the major assumptions, including their references. The discount rate is 8.5% [15] and the plant lifetime is 25 years [8]. For grid-based electricity use, we assume a delivered cost of $69/MWh, which is the average industrial electricity price in the U.S. from 2017 to 2021 [16]. The natural gas baseline cost is $4/mmbtu, which is the average industrial natural gas price in the U.S. from 2017-2021 [17]. In our sensitivity analysis, we vary these price assumptions. These prices are utilized for an initial assessment of the levelized costs. Later research efforts will explore regional differences in the cost of fuels and capital.

The overnight capital cost for the DRI and EAF equipment is $578 per tonne of annual capacity [18]. The natural gas usage of the Direct Reduced Iron process is modelled on the MIDREX DRI process fed by high quality iron ore pellets (90-94 Fe) to produce 1.4% carbon DRI [19]. The DRI process uses 11.52 GJ HHV of natural gas per tonne crude steel [19]. The DRI process also requires 327 MWh of electricity per tonne of crude steel [20]. The electric arc furnace requires 753 MWh of electricity per tonne of crude steel and has a feedstock of 100% DRI [19, 20]. The Direct Reduced Iron process consumes 1.5 tonnes of iron ore for each tonne of crude steel at a price of $144/tonne iron ore [20]. The process assumes conversion rates of 1.2 tonnes DRI per tonne of crude steel [8] and 1.03 tonne crude steel per tonne of hot rolled steel [21]. The electric arc furnace consumes graphite electrodes, lime and alloy materials. The labor costs are \$76.95/tonne crude steel and fixed O&M costs are 3% of the capital expense [20].

The hot rolling finishing process is assumed to be the same across all steelmaking pathways. Since the markup methodology is used to compute relative costs, our calculations include the energy usage for the finishing process to account for the CO_2 emissions but exclude the capital cost of the finishing plant. The hot rolling plant is assumed to use 1.05 GJ HHV of natural gas per tonne of hot rolled steel and requires 0.11 MWh of electricity per tonne of hot rolled steel [21].

The DRI-EAF with CCS production pathway has a capture unit to achieve 90% capture rate of CO_2 from the DRI stack gas. The impact of flue gas composition on the cost of CO_2 capture on DRI facilities is not well studied, so here we assume a constant cost. To estimate the cost of the capture unit, we utilized costs from a supercritical coal power plant with carbon capture as modelled by the DOE [22]. This process has one CO_2 capture system which uses a Cansolv absorption system, two CO_2 compression systems and achieves a 90% capture rate [22].

The DOE study [22] assumes that the coal power plant stack gas has a pressure of 14.8 psi and 12.46 mol% CO_2. This is representative of a low-pressure capture unit that could be utilized in the DRI process; as the Midrex DRI stack gas has a pressure 14.6 psi and contains 24 mol% CO_2 [40]. Another DRI process design is the Hyl/Energiron DRI which is capable of a 90% capture rate utilizing one CO_2 capture unit. This process design has selective removal of CO_2 from the DRI top gas.

For example, *Emirate Steel* has two Hyl/Energiron DRI plants located in Abu Dhabi which have been operating since 2016 and capture CO_2 for reuse in enhanced oil recovery [8, 21]. To achieve up to 90% capture rate, the outlet stream of the CO_2 capture unit must additionally be processed through a physical adsorption system to separate hydrogen for use as fuel in the heater burners and the carbon compounds are then fed to the process system [21]. This reduces the CO_2 emissions from the heater stack gas. Since the process is set up to selectively separate CO_2 from the system, there is minimal capital cost increase to the base plant.

The capital cost, fixed cost, and variable O&M costs in \$/tonne of captured CO_2 are derived from the DOE's modelling of a Supercritical Coal Power Plant with CCS [22] and incorporated into the levelized cost of steel. The electricity usage from the CCS process was calculated to be ~300 kWh/tonne captured CO_2. This includes the electricity for CO_2 capture, compression as well as the plant's output power loss due to energy being used to supply steam for the capture unit. The electricity usage for the DRI-EAF with CCS plant was increased by this amount over the baseline DRI-EAF process. The DRI-EAF with CCS process captures ~1Mtpa of CO_2 which is then transported and stored in an underground formation. The cost of CO_2 transportation and storage is \$10.53/tonne CO_2 which is reflective of costs for onshore pipeline transportation and storage in saline aquifers, for 3.2 Mtpa of CO_2 transported 100 miles [6]. The levelized cost of steel from the DRI-EAF with CCS production pathway is 6.6% more expensive than the conventional DRI-EAF production pathway.

The Hydrogen DRI-EAF production pathway utilizes the same processes as the baseline natural gas DRI-EAF pathway, except that hydrogen replaces natural gas as the reducing agent in the DRI process. The assumption for the baseline cost calculations are that the hydrogen plant, renewable energy plant, and steel plant are all collocated. Approximately 80.89 kg (11.5 GJ HHV) of hydrogen are required per tonne of crude steel [19]. Additionally, 1.89 GJ HHV of natural gas is needed for heating and to ensure a carbon content of 1.4% in the DRI. The hydrogen price for the feedstock is based on the levelized costs of green and blue hydrogen as calculated in Section 4.2. The levelized cost of *Blue* hydrogen DRI-EAF is 18% greater than the conventional DRI-EAF production pathway and the *Green* hydrogen DRI-EAF cost is 77% greater.

We compare our calculations with the levelized cost of steel in the 2020 IEA Iron & Steel Technology report [8]. This report has crude steel production costs with ranges to account for regional variations in cost. Costs for the natural gas based DRI-EAF process are between ~\$400-\$590/tonne crude steel. For DRI-EAF with CCS, production costs range from ~\$450-\$650/tonne crude steel and electrolytic hydrogen DRI-EAF production costs range from \$500-850/tonne crude steel [8]. BF-BOF costs range from ~\$350-\$475/tonne crude steel. The high end of the IEA's estimate for the BF-BOF production cost is graphed below to enable comparison of the cost of traditional steel technologies to that of the advanced steel technologies. Our calculations summarized in Figure 1 ($580 for DRI-EAF, $620 for DRI-EAF with CCS, and $680 for *Blue* H2 DRI-EAF) are consistent with the ranges assessed by IEA. Our estimate for *Green* H_2 DRI-EAF is higher than IEA.

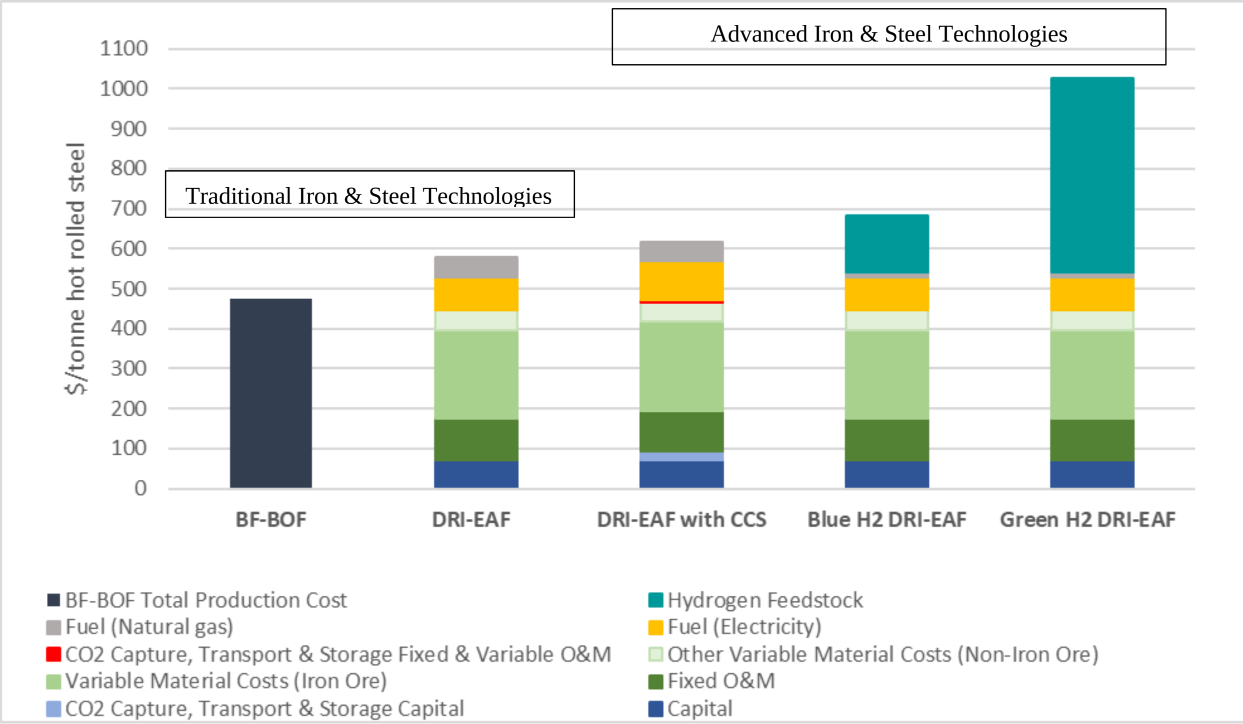

Figure 1. Steel Production Costs and Input Shares

In Figure 2, we provide CO_2 emission intensity calculations for different steelmaking pathways, where direct emissions are represented by solid colors, and indirect emissions (i.e., from electricity) are represented by shaded areas. These CO_2 emission estimates are provided for the same boundaries as those used in the levelized cost analysis (iron making to hot rolled steel). However, the *Blue* hydrogen DRI-EAF emission intensity in this figure includes the direct and indirect (Grid electricity) emissions resulting from the *Blue* hydrogen production process. As detailed in Section 4.2, the *Blue* hydrogen pathway is modelled on an Autothermal reforming plant with CCS which utilizes substantially more electricity than a Steam methane reforming plant with CCS. Even with the current emission intensity of electricity production, advanced steelmaking pathways offer a substantial mitigation potential. With the full decarbonization of electric grid, indirect emissions would be eliminated and advanced technologies would provide drastic reductions relative to the traditional steelmaking processes.

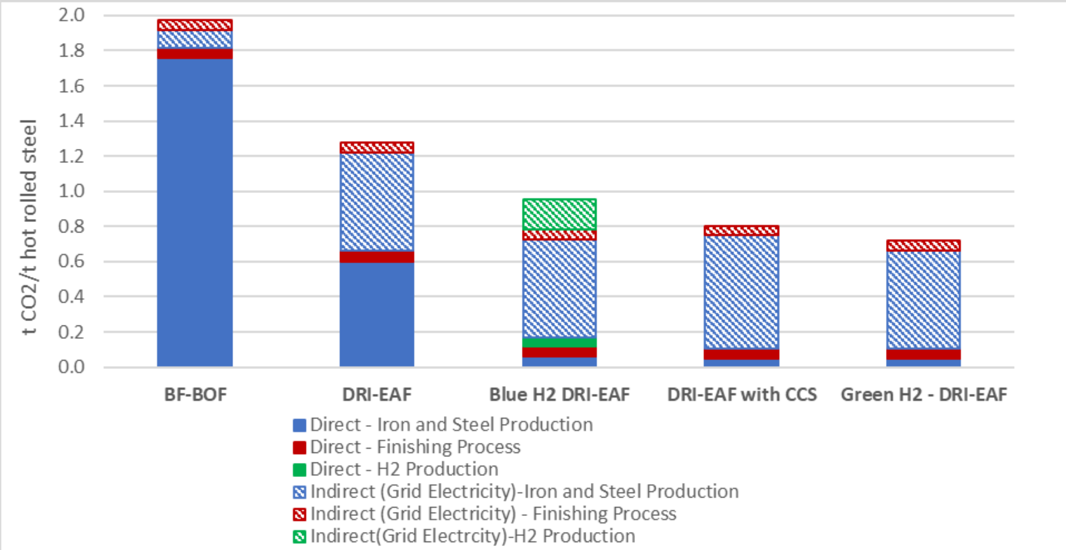

Figure 2. CO_2 Emission Intensity for Steel Production Pathways.
Note: The steel production emission intensities in this figure were calculated using the emission factors utilized by the World Steel Association for reporting Iron & Steel sectoral emissions and are representative of global averages: Grid electricity CO_2 emission factor: 504 kg CO_2/MWh; natural gas CO_2 emission factor: 56 kg CO_2/GJ HHV; coal CO_2 emission factor: 95 kg CO_2/GJ HHV. Calculations exclude process emissions from lime and graphite, which are estimated as 0.03 tCO_2/t steel for the DRI-EAF process. [23].

4.2. Levelized Cost Calculations for Hydrogen

To determine the levelized cost of hydrogen, we consider four different hydrogen production pathways: *Green*, *Blue*, *Yellow* and *Grey* hydrogen. Because we assume that the hydrogen plant, and steel plant are collocated. The production cost calculations do not include hydrogen transportation and storage costs. In the same way, electricity transmission and distribution costs for renewable electric energy are not included since we also assume the renewable energy plant is also nearby. Our sensitivity analysis explores the additional costs incurred from transportation and storage costs. The details of calculations are provided in Appendix B.

The *Green* hydrogen production pathway is modelled on a Polymer Electrolyte Membrane (PEM) electrolyzer powered by a dedicated onshore wind energy plant. We focus on the PEM electrolyzer technology over the more mature alkaline electrolyzer because the PEM electrolyzer has a smaller footprint and higher current density which makes it more advantageous to deploy at a large scale [18]. The PEM electrolyzer also operates at a higher pressure which eliminates the need for compression of the hydrogen product [18]. The largest green hydrogen project is currently a 150 MW alkaline electrolyzer, brought online by a Chinese chemical manufacturer at the end of 2021 [27]. However, H2 Green Steel has announced plans to construct a 1 GW electrolyzer to power a 2 Mtpa iron plant [28].

We assume that the *Green* hydrogen plant has a capacity of 1 GW, and it produces ~92,000 tonnes of H_2 annually. This amount is sufficient to supply hydrogen for a 1.14 Mtpa DRI-EAF iron and steel plant. The wind plant capacity factor is assumed to be 43%, which is the average wind resource level in the United States as reported by NREL's 2021 Annual Technology Baseline report [29]. The wind plant is oversized 1.45 times larger than the electrolyzer's capacity to increase the electrolyzer's utilization rate to 57%. The oversizing ratio was selected by optimizing for the lowest green hydrogen production cost. The wind plant capacity factor was calculated using hourly profiles for 2019 from [30]. The wind plant capacity was scaled by the oversizing factor and the electrolyzer utilization rate is determined based on electricity available in each hour. The overnight capital cost of the hydrogen plant is \$1,622/kWe. This assumes a direct installed capital expense of \$1,065/kWe [31], indirect capital expense equal to 27% of the direct CapEx [31], project contingency of 15% of direct CapEx [32, 33] and owner's cost of 10.65% of direct CapEx [31].

The stack replacement cost is estimated at $331/kWe and cost is annualized over the stack lifetime of 60,000 hours [24, 32, 34]. The electrolyzer electricity consumption is 54.3 kWh/kg [32]. The operating costs for the green hydrogen plant consist of fixed O&M of ~ 4% of the capital cost and variable costs due to a water usage of 4.76 gal of water per kg of hydrogen [32]. The overnight capital cost and labor costs for the onshore wind system are based on values from the 2021 NREL Annual technology baseline for a plant of Class 4 resource, moderate rating, in year 2020 [29]. The annualized capital and labor costs of the oversized renewable energy system are summed with the annualized capital and labor requirements of the hydrogen plant, and levelized over the plant's annual hydrogen production. The majority of the production cost (~50%) is incurred to meet the electricity demand of the plant.

The *Yellow* hydrogen production pathway represents hydrogen production using a PEM electrolyzer powered by grid electricity. It is not inherently a low carbon pathway because the indirect emissions due to the electricity vary with the CO_2 intensity of the electrical grid. In the future, as the electrical grid becomes decarbonized, *Yellow* hydrogen would also represent a low carbon hydrogen production pathway. Relying on the grid electricity enables this pathway to have a higher utilization rate of 90%. The *Yellow* hydrogen plant only requires a 633 MW electrolyzer capacity to produce the equivalent amount of hydrogen as the corresponding *Green* hydrogen production pathway.

The 2021 Lazard report on levelized cost of hydrogen computes a cost range from $1.96 to $5.24 for hydrogen produced from a 100 MW PEM electrolyzer [35]. Utilizing the mean values reported in Lazard's key cost assumptions yields a hydrogen production cost of $3.29/kg. Our hydrogen production costs are on the high end of Lazard's numbers because we have utilized a higher capital cost estimate, higher fixed O&M cost estimate, and an electricity cost that is on the high end of Lazard's assumptions.

As mentioned, electrolysis is one of the methods to produce hydrogen; however currently the majority of hydrogen is produced using natural gas in a process called steam methane reforming. The *Grey* hydrogen production pathway represented in this work is modeled on a steam methane reforming plant. The plant design, capital costs, and non-energy operating costs are based on 2022 DOE/NETL report on natural gas reforming technologies [36]. This plant produces ~158,000 tonnes H_2 annually, operating at 90% capacity factor, which is enough hydrogen to support a 1.96 Mtpa iron and steel plant.

For the *Blue* hydrogen production pathway, we use an autothermal reformer (ATR) with a carbon capture unit using MDEA to remove the CO_2 from the high-pressure syngas stream. This enables the process to achieve a capture rate of 94.5% [36]. It is more challenging to achieve the same capture rate from the SMR process because it requires a capture unit on the flue gas. Other advantages of the autothermal reformer include its' more compact design and ability to operate at a higher temperature/pressure, which reduces the need for additional hydrogen compression [37].

The *Blue* hydrogen levelized cost is based on an ATR plant which produces 216,000 tonnes of hydrogen annually which is enough to supply a 2.68 Mtpa iron and steel plant. The ATR plant design, capital costs, and non-energy operating costs are based on 2022 DOE/NETL report on natural gas reforming technologies [36]. The cost for the CO_2 transportation and storage is estimated as $10.53/tonne CO_2 which is based on transporting ~3.2 Mtpa of CO_2 approximately 100 miles [6].

Figure 3 illustrates hydrogen production costs and input shares for different pathways. Under the baseline assumptions, *Grey* hydrogen has the lowest cost of $1.08/kg H_2, *Blue* hydrogen costs $1.70/kg H_2, *Yellow* hydrogen costs $5.66/kg H_2, and *Green* hydrogen cost is $5.82/kg H_2.

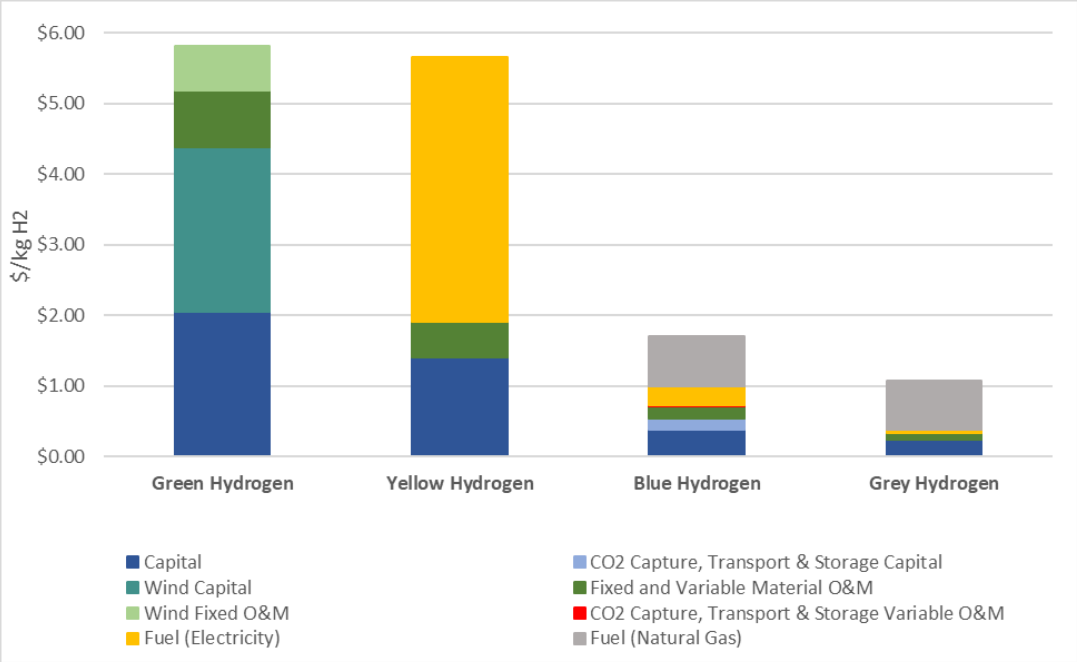

Figure 3. Hydrogen Production Costs and Input Shares

Figure 4 provides a comparison of the CO_2 emission intensities for different hydrogen production pathways. As before, direct emissions are represented by a solid color, and indirect emissions (i.e., from electricity) are represented by shaded areas. Currently, *Yellow* hydrogen has the highest emission intensity due to indirect emissions (which would be eliminated with grid decarbonization). *Blue* hydrogen offers substantial emission reductions relative to *Yellow* hydrogen and *Grey* hydrogen. *Green* hydrogen has zero emissions.

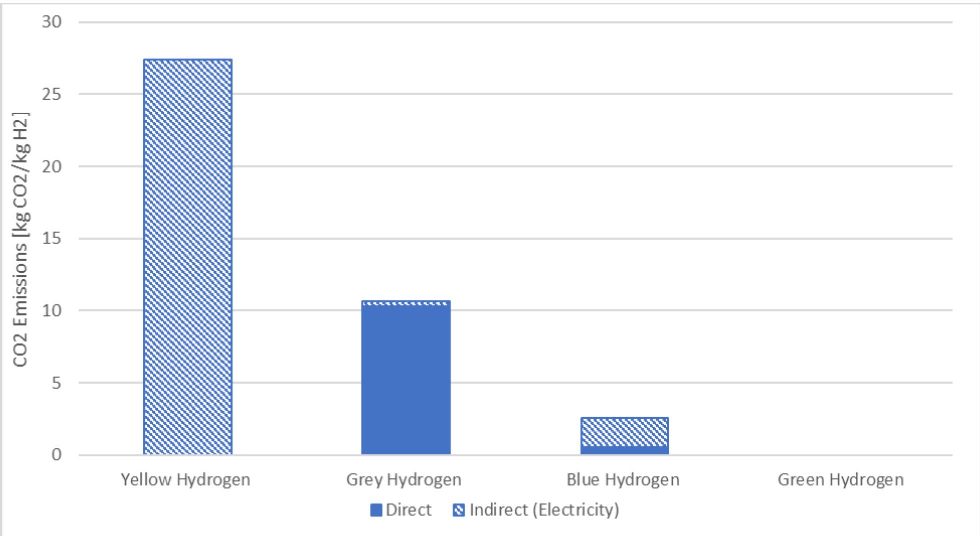

Figure 4. CO_2 Emission Intensity for Hydrogen Production Pathways.
Note: The hydrogen production emission intensities in this figure were calculated using the emission factors utilized by the World Steel Association for reporting Iron & Steel sectoral emissions and are representative of global averages. Grid electricity CO_2 emission intensity is 504 kg CO_2/MWh, natural gas CO_2 emission intensity is 56 kg CO_2/GJ [23].

4.3. Sensitivity Analysis for Input Costs

The *Blue* hydrogen production cost varies significantly depending on the natural gas price. As seen in Figure 5, the deviation from the baseline natural gas price of $4/mmbtu can cause large increases in the hydrogen production cost. The high natural gas price of $32/mmbtu is representative of the natural gas prices seen in Europe in Q1 of 2022 [38]. A decrease in natural gas price to $2/mmbtu would decrease hydrogen cost by $0.35/kg H_2. An increase of natural gas price to $32/mmbtu would increase hydrogen production cost by almost $5/kg H_2. Changes in electricity prices have relatively smaller impacts on the costs of *Blue* hydrogen production.

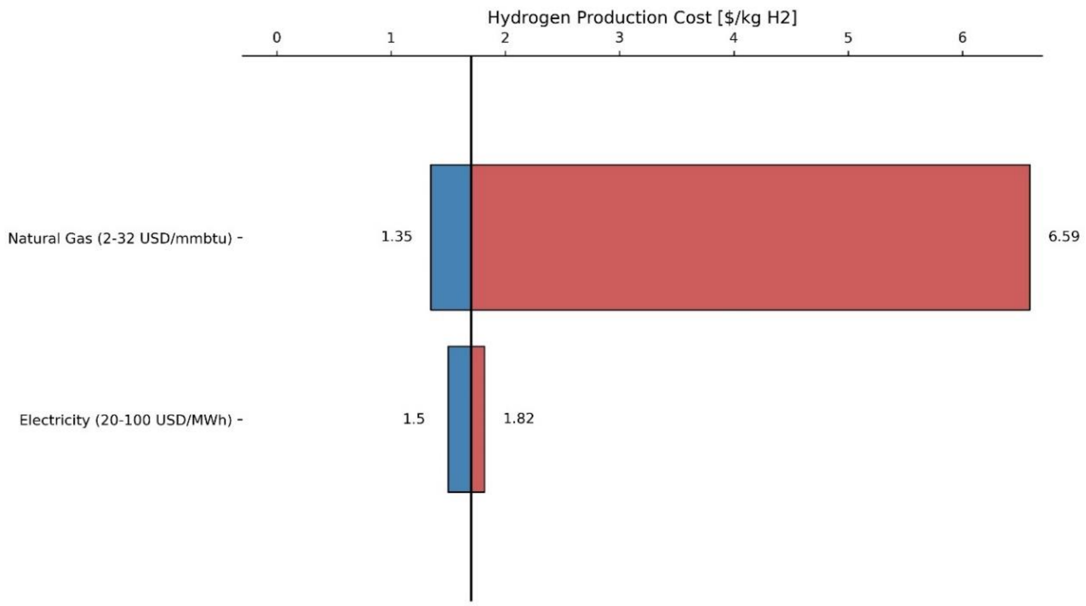

Figure 5. Blue Hydrogen Cost Sensitivity to Energy Prices

The *Green* hydrogen production cost is highly dependent on the capacity factor of the renewable energy system. Assuming a low wind capacity factor of 35% results in a higher wind plant oversizing factor of 1.73 which yields an electrolyzer utilization rate of 54%. The increased capital investment required to enable the higher electrolyzer utilization rate results in an overall increase in the production cost of $0.90/kg H_2. Alternatively, in a region with a rich wind resource (with a capacity factor of 56%), there is minimal oversizing of the wind plant required (1.18) and the electrolyzer utilization rate is 63%. This reduces the production cost by $1.01/kg H_2.

Another factor that greatly influences the production cost of *Green* hydrogen is the plant's capital cost. Many studies have different scopes for capital costs and may not reflect the actual total capital requirement for a hydrogen plant. Cost estimates such as those given by the IEA's Future of Hydrogen report reflect only the direct costs for equipment including the electrolyzer, power electronics, gas conditioning and balance of plant [18]. Indirect costs, owner's costs and project contingency resulted in an increase in total capital requirement by an additional 50%. The IEA predicts direct capital costs between $1,100-1,800/kWe for values today and by 2030 a reduction to $650-$1,500/kWe [18]. Figure 6 shows cost changes for the total capital requirement between $1,000/kWe and $2,000/kWe. This corresponds to a range in green hydrogen production cost of $5.07 to $6.27/kg.

The levelized cost of hydrogen calculations assumed that all of the assets were co-located. However, areas rich in wind resources may not be located where it most desirable/feasible for steel to be produced. One alternative is to site hydrogen production and renewable electricity generation in one location and then transport the hydrogen to the steel plant. The IEA estimates that pipeline transportation costs for hydrogen can be up to $2/kg if transporting up to 3,000 km [18]. Alternatively, the hydrogen plant can be collocated with the steel plant, in which case the renewable electricity must be transmitted to the hydrogen plant. Transmission & Distribution costs for renewable electricity can be estimated at $0.03/kWh [15]. Both of these alternatives would increase the levelized cost of hydrogen. In addition, hydrogen storage is currently excluded from our hydrogen production cost estimates. Hydrogen storage might be required in some cases of *Green* hydrogen production because of intermittent operations of renewable power. The IEA reports costs of $0.59/kg hydrogen for storage in salt caverns, which is one of the most cost-effective options but it is also the one which is highly dependent on the geologic features of a location [18]. Figure 6 shows an increase in cost by $0.59/kg H_2 in this case.

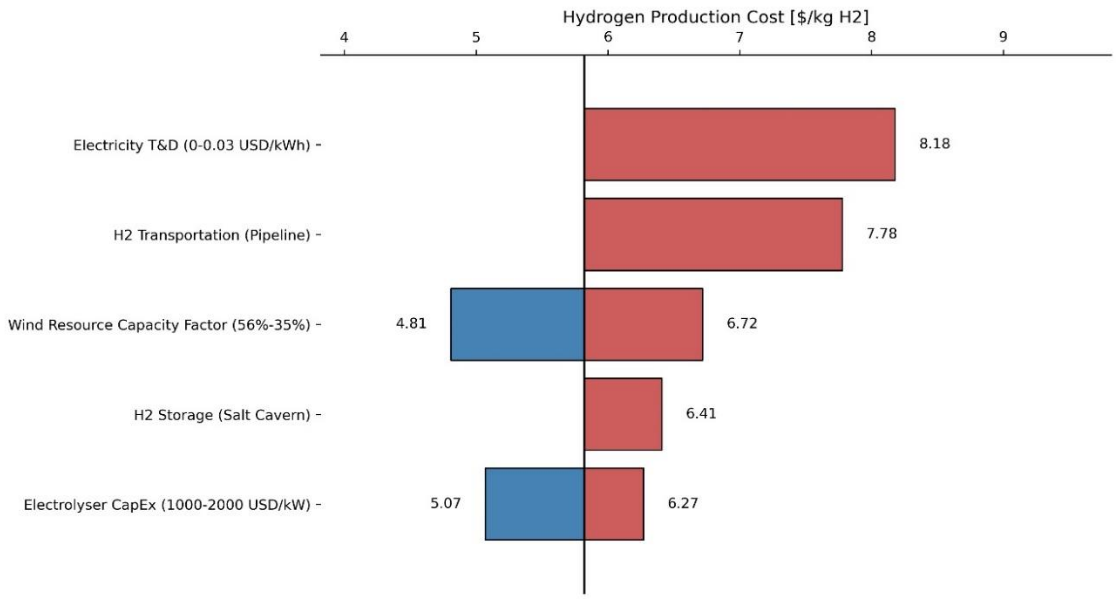

Figure 6. Green Hydrogen Cost Sensitivity

The Hydrogen DRI-EAF pathway's steel production cost is highly dependent on the cost of the hydrogen feedstock. Figure 7 shows the change in the baseline production cost over a hydrogen production cost range of $1/kg to $10/kg. The low-end estimate is representative of the current *Grey* hydrogen production cost. The high end of the estimate is representative of a *Green* hydrogen production cost using a low capacity factor wind resource, incurring electricity transmission & distribution costs, utilizing geologic storage for the hydrogen and assuming high capital expense estimates. The baseline H2 DRI-EAF production cost is ~$680/tonne steel, based on the blue hydrogen production cost of $1.70. The high end of the hydrogen production cost estimate increases this cost by an additional ~$690/tonne steel, essentially doubling the total cost.

The iron & steel production cost is also dependent on the cost of iron ore. Figure 7 also shows the effect of a range of iron ore prices from $60/tonne to $200/tonne. The low-end iron ore cost of $60/tonne is representative of global iron ore prices from 2017 [39]. The IEA Future of Hydrogen's steel production cost estimates are based on a price of $58.80/tonne for iron ore (58% Fe content) [18]. The high end of the iron ore price range is $200/tonne and it is representative of global iron ore prices in Q1 2021. The iron ore price for the DRI process is likely towards the high end of this estimate because the DRI process requires iron ore of higher quality (> 65% Fe) than that required by the blast furnace process [19].

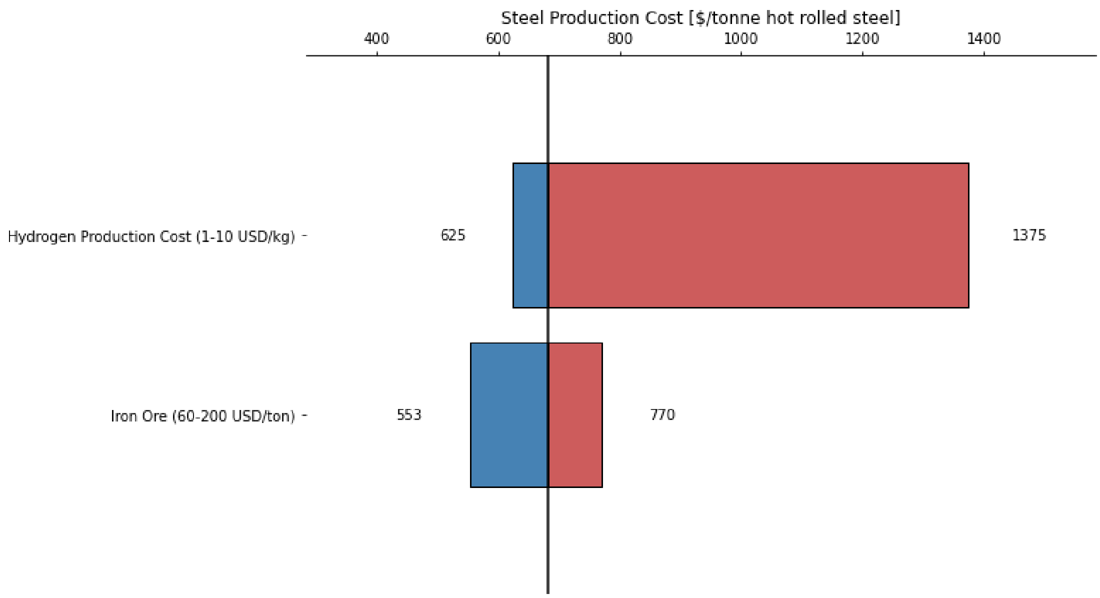

Figure 7. DRI-EAF Cost Sensitivity

Figure 8 illustrates the impact of natural gas prices on the levelized cost of steel for different steel production pathways. The baseline natural gas price used in our analysis is $4/mmbtu. At this price, the Green Hydrogen DRI-EAF production cost is approximately double the cost of the baseline DRI-EAF process. However, at very high natural gas prices (about $50/mmbtu), production costs for these two technologies are comparable. The price of *Blue* hydrogen also increases with increasing natural gas price, which results in the correspondingly increasing prices for the Blue Hydrogen DRI-EAF process.

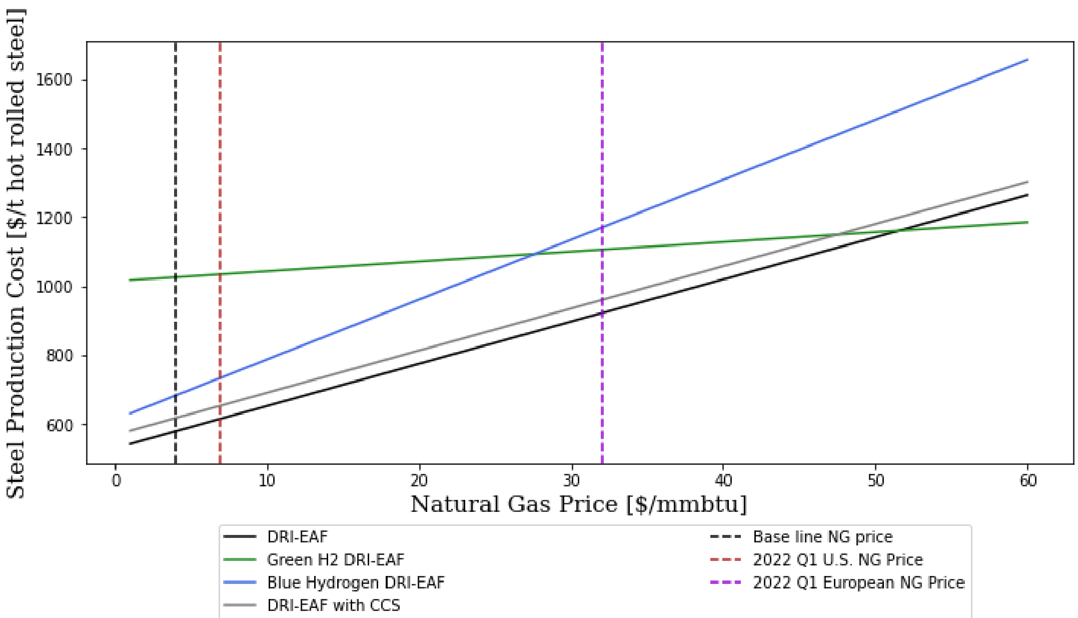

Figure 8. Steel Production Cost Sensitivity to Natural Gas Price

The impact of carbon pricing on steelmaking costs of different steel production pathways is shown in Figure 9. The steel production cost for the natural gas based DRI-EAF pathway rises the steepest with carbon price in Figure 9, because it has the highest direct CO_2 emissions among the production pathways that we consider. At a carbon price above \$71/tCO_2, the DRI-EAF with CCS has a lower steel production cost than the DRI-EAF pathway. Cost penalty on emissions makes DRI-EAF more expensive than *Blue* H_2 DRI-EAF pathway at a carbon price above \$205/tCO_2, and more expensive than the *Green* H_2 DRI-EAF above \$807/tCO_2.

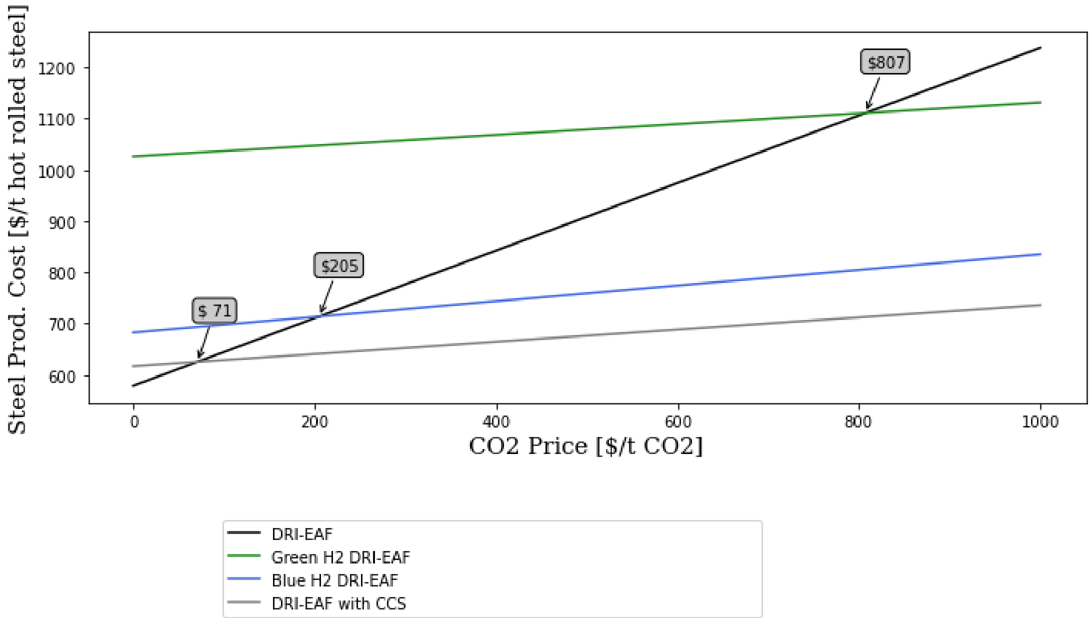

Figure 9. Steel Production Cost Sensitivity to Carbon Price on Direct Emissions

5. Illustrative Scenarios with Integrated Assessment Modeling

We have incorporated advanced technology pathways for low-emission steelmaking and hydrogen production into the MIT Economic Projection and Policy Analysis (EPPA) model [3, 14, 41]. Traditional iron & steel in the EPPA model is representative of all current iron & steel production technologies including BF-BOF, DRI-EAF and scrap steel. Our preliminary assessment (Figure 10) shows that cost premiums over traditional steelmaking are substantial and the resulting deployment of CCS and H_2 based advanced steelmaking is rather limited. This result is driven by a substantial emission reduction potential in traditional steelmaking. In the EPPA model, CO_2 emissions in the iron & steel sector are drastically reduced by an increase in energy efficiency in traditional steelmaking, switching from BF-BOF to DRI-EAF, and an increase in the use of recycled steel scrap. As a result, advanced steel technologies have to compete with an increasingly efficient traditional steelmaking. The global CO_2 emissions from the iron & steel sector are reduced from about 2 GtCO_2 in 2020 to about 0.01-0.2 GtCO_2 in 2070 (this result is sensitive to assumptions about the options for traditional steelmaking, and deployment of negative emission technologies like direct air capture and bioenergy with carbon capture and storage).

Future technology costs decline endogenously in the EPPA model via learning and other factors such as adjustment costs and monopoly rents [42]. While we continue to explore different settings, Figure 10 presents several illustrative results where relative costs (markups) of advanced steelmaking and hydrogen production are reduced. The cost of advanced steelmaking in this scenario is equal to the production cost of the conventional DRI-EAF process. The low markup values used for the *Green* and *Blue* hydrogen production cost is based on a cost of \$1/kg H_2 which is roughly equivalent to current *Grey* hydrogen production costs. We also tested a scenario where it is more difficult to switch to electrification of traditional steelmaking (represented by low elasticity of substitution).

Restricting options for decarbonization of traditional steelmaking and reducing the cost of advanced steelmaking (e.g., by government support and regulations or by technological innovation) increases the shares of the advanced steelmaking pathways. These results should be treated as preliminary as we continue to explore different settings for cost reductions and government support to decarbonize iron and steel industry.

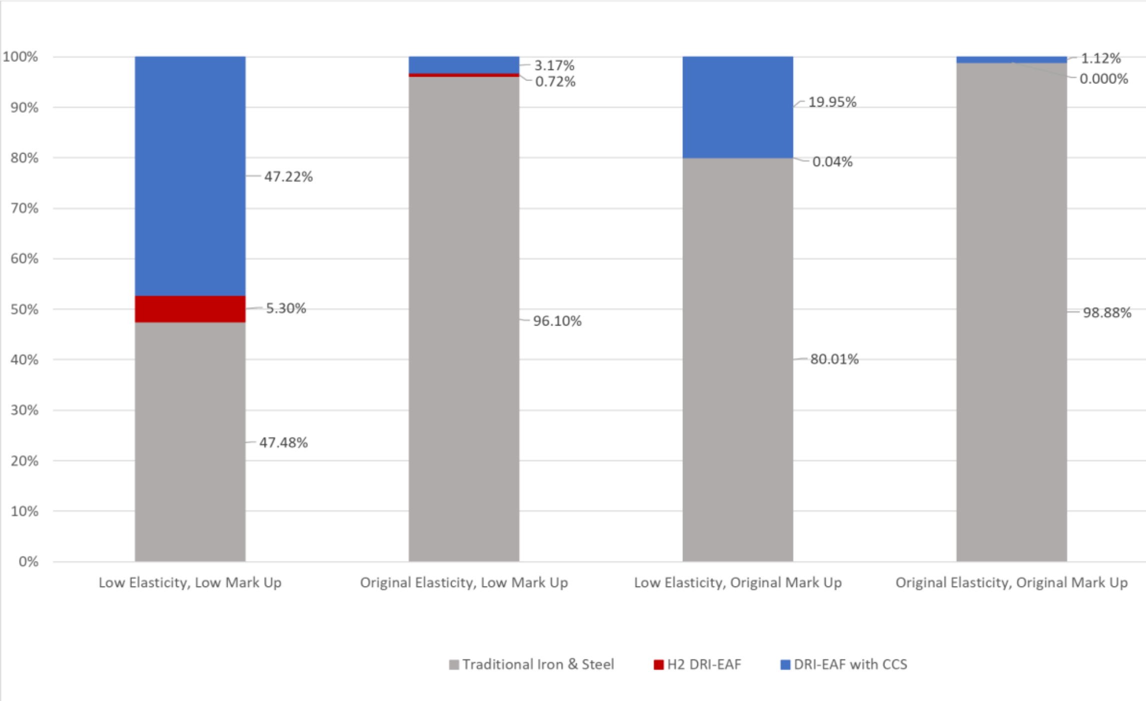

Figure 10. Shares of Advanced Steelmaking Pathways in 2070 in a 1.5C Scenario. Note: Traditional Iron & Steel in the EPPA model is representative of all current Iron & Steel production technologies including BF-BOF, DRI-EAF and scrap steel EAF. Elasticity represents an easiness for substitution between different energy inputs. Markups are relative costs of advanced steelmaking pathways to traditional steelmaking. Original markups refer to those derived in this paper. Low markups represent the cost of advanced steelmaking being equal to the production cost of the conventional DRI-EAF process and lower hydrogen production costs as described in Section 5. Original elasticities are described in [41]. Low elasticities restrict electrification of traditional steelmaking.

6. Concluding Remarks

The exact pathways for CCS and hydrogen deployment in steelmaking are highly speculative at this point. Our preliminary analysis shows that deployment of advanced technologies will depend on the level of carbon prices and/or financial incentives. The current levelized costs of advanced steel making is greater than the DRI-EAF pathway by approximately 6.6% in the case of CCS and between 18-77% for hydrogen deployment (Appendix A). The range of costs for hydrogen implementation in the DRI process is due to the cost variation between *Blue* and *Green* hydrogen. As demonstrated in the sensitivity analysis, a carbon tax on direct CO_2 emissions can assist in compensating for the higher costs of the advanced steel technologies. A high CO_2 price of above \$807/ tCO_2 is required to make the traditional DRI-EAF process more expensive than the *Green* hydrogen DRI-EAF, whereas lower CO_2 prices can make the DRI-EAF process more expensive than the DRI-EAF with CCS and *Blue* Hydrogen DRI-EAF pathways: above \$71/tCO_2 and \$205/ tCO_2, respectively (Figure 9). However, implementation of new technologies will also encounter adjustment costs related to initial penetration and the rate of diffusion will be influenced by numerous economic factors. Actions in the forms of research and development (R&D), technology demonstration, technology transfers, infrastructure development and policy incentives could speed up the transition to a low-emitting steelmaking industry. Our cost evaluation can also be used for other energy-economic and integrated assessment models to provide insights on future decarbonization pathways.

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Appendix A. Iron & Steel Production Cost Assumptions

Financial Parameters	**Value**
Interest Rate for Construction Period	4 %
Discount Rate	8.5%
Currency	2016 USD
Grid Electricity Cost	$ 69/MWh
Natural Gas Cost	$4/mmbtu [$3.77/GJ HHV]

Parameter	**Units**	**DRI-EAF**	**DRI-EAF with CCS**	**Hydrogen DRI-EAF**	**References**
Steel production	Mtpa	2	2	2	
Capacity Factor	%	90%	90%	90%	
Overnight Capital Cost	$/tonne crude steel/yr	$578.20	$578.20 (DRI-EAF) $127.91 ($CO_2$ Capture Unit)	$578.20	*[18]* *CCS: [22]*
Plant Lifetime	years	25	25	25	*[18]*
Construction Years	years	3	3	3	
Total Capital Requirement	$/tonne crude steel	$70.31	$85.86	$70.31	
Fixed O&M	$/tonne crude steel	$21.59	$21.59	$21.59	*[20] 3% of Total CapEx*
CCS Fixed O&M	$/tonne crude steel	N/A	$2.54		*[22]*
Labor	$/tonne crude steel	$76.95	$76.95	$76.95	*[20]*
Iron Ore Price	$/tonne iron ore	$144	$144	$144	*[20]*
Other Variable Material Prices	$/kg electrode	$5.78	$5.78	$5.78	*[20]*
	$/kg lime	$0.14	$0.14	$0.14	*[20]*
	$/kg alloy	$2.57	$2.57	$2.57	*[20]*
CCS Variable O&M	$/tonne crude steel	N/A	$2.28	N/A	*[22]*
Hydrogen Usage	Kg/tonne crude steel	**N/A**	N/A	80.89	*[19]* **Converted from 71.9 kg H2/t DRI to kg H2/t crude steel*
Electricity Usage	kWh/tonne crude steel	327 (DRI)	327 (DRI) 160 (CO_2 Capture, compression, heat)	327 (DRI)	*[20]* *CCS: [22]*
	kWh/tonne crude steel	753 (EAF)	753 (EAF)	753 (EAF)	*[20]*
	kWh/tonne hot rolled steel	110 (Hot Rolling)	110 (Hot Rolling)	110 (Hot Rolling)	*[21]*
Natural Gas Usage	GJ HHV/tonne crude steel	11.52 (DRI)	11.52 (DRI)	1.89 (DRI)	*[19]*
	GJ HHV/tonne hot rolled steel	1.05 (Hot Rolling)	1.05 (Hot Rolling)	1.05 (Hot Rolling)	*[21]*
CO_2 Capture Rate	%	N/A	90%	N/A	*[8]*
CO_2 Transportation & Storage Cost	$/t CO_2	N/A	$10.53	N/A	*[6]*
Levelized Cost of Steel	$/tonne hot rolled steel	$578.77	$617.01	$682.81 (*Blue* H2) $1026.08 (*Green* H2)	
Ratio of Advanced Technology to Baseline Technology		1	1.066	1.18 (Blue H2) 1.77 (Green H2)	

Material Usage Rates	**Units**	**Value**	**References**
Iron Ore	Tonne/tonne crude	1.504	*[20]*
Graphite Electrode	Kg/tonne crude steel	2	*[20]*
Lime	Kg/tonne crude steel	50	*[20]*
Alloy	Kg/tonne crude steel	11	*[20]*
DRI	Tonne/tonne crude steel	1.2	*[8]*
Crude Steel to Hot Rolled Steel	Tonnes/tonne	1.03	*[21]*

Appendix B. Hydrogen Cost Assumptions

Financial Parameters	Value
Interest Rate for Construction Period	4 %
Discount Rate	8.5%
Currency	2016 USD
Grid Electricity Cost	$ 69/MWh
Natural Gas Cost	$4/mmbtu [$3.77/GJ HHV]

Parameter	Units	Green Hydrogen	Yellow Hydrogen	Blue Hydrogen	Grey Hydrogen	References
Actual Hydrogen Production	Tonnes/yr	91,972	91,972	216,810	158,670	
Actual Hydrogen Production	GJ H2 HHV/yr	13,074,119	13,074,119	30,820,269	22,555,487	
Capacity Factor	%	57%	90%	90%	90%	
Overnight Capital Cost	$/GJ H2 HHV/yr	$124.08 [H2 Plant] $139.05 [Wind Plant]	$78.59	$28.20	$14.66	*[31] &[29], [31], [36], [36]*
Construction Years	Years	1 [H2 Plant] 3 [Wind Plant]	1	3	3	*[31] & [29], [31], [36], [36]*
Total Capital Requirement [H2 Plant]	$/GJ H2 HHV/yr	$284.78	$81.73	$30.16	$15.69	
Stack Replacement Cost	$/GJ H2 HHV/yr	$25.32	$16.04	N/A	N/A	
Plant Lifetime	Years	20	20	20	20	
Capital Recovery Required	$/GJ H2 HHV	$27.42	$6.94	$2.71	$1.66	
Stack Lifetime	Years	12	7.6	N/A	N/A	*[32]*
Capital Recovery Required for Stack	$/GJ H2 HHV	$3.44	$2.95	N/A	N/A	
Fixed O&M	$/GJ H2 HHV	$5.54 [H2 Plant] $4.45 [Wind Plant]	$3.51	$0.77	$0.45	*[32]*
Variable O&M	$/GJ H2 HHV	$0.08	$0.08	$0.44	$0.28	*[32] [36]*
Hourly Electricity Demand	MW/h	1000	633	110	12.65	*[32], [36]*
Hourly Heat Rate	Mmbtu/hr	N/A	N/A	4804	3518	*[36]*
CO2 Transportation & Storage Cost	$/t CO2	N/A	N/A	$10.53	N/A	*[6]*
Levelized Cost of Hydrogen Production	$/GJ H2 HHV	$40.92	$39.83	$11.95	$7.62	
Ratio of Advanced Technology to Baseline Technology	-	10.8	10.6	3.2	2.0	

Appendix C. Wind Capacity Factors

2019 Resource Profiles, Dataset: Merra 2; Land Based Wind Turbines: Vestas V90 2000; Turbine Height: 90m. Source: Pfenninger, S., I. Staffell (2022). https://www.renewables.ninja [30].

Resource Level	Capacity Factor	Location
Low	35 %	33.07868615030591, -95.44870293943644
Average U.S. Wind Resource Level	43%	34.88447558813019, -97.21912666481369
High	56%	64.34776768088481, -17.713612479642226

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