Cost Estimates for an Australia Germany Green Iron and Steel Value Chain

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We welcome and seek stakeholder feedback on this report.
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Citation

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Project Scope

This report conducts a **techno-economic assessment** of a potential green iron and steel value chain between Australia and Germany. Both countries have significant clean energy and emission reduction targets, and key roles in the global steel industry. This report forms the **third part** of a series of **four** reports. The first report builds the case for developing a green iron and steel value chain between Australia and Germany. The second report explores **technology pathways** for green iron and steel production, and the fourth report summarises **government, industry, and academic consultations** on the current state of play and the roadmap for developing a green iron and steel industry.

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Executive Summary

This report forms the **third instalment** in a series of **four** reports examining opportunities to establish a green iron and steel value chain between Australia and Germany. This report provides cost estimates for the following three key value chain scenarios:

- **Scenario 1:** Export iron ore and renewable hydrogen (or derivatives) to Germany for green iron and steel production.
- **Scenario 2:** Produce green iron in Australia and export it, along with renewable hydrogen (or derivatives), to support green steel production in Germany.
- **Scenario 3:** Produce both green iron and green steel in Australia for export to Germany, where further processing into specialty steels would occur.

Noting that the **first two scenarios are most viable** under existing industry structures in Australia and Germany.

The analysis assessed each pathway for meeting 1%, 10%, 25%, 50%, and 100% of Germany's steel demand, considering investment, infrastructure, renewable energy, CO_2 emissions, and feedstock requirements. Additionally, all models developed in this study are being released as **open-source tools**.

Key findings include:

- **Scenario 1**: Meeting **10% of Germany's steel demand** under this scenario would require approximately **5.34–5.78 Mt of iron ore**, **26.3 PJ (0.219 Mt) of hydrogen gas**, and **6.67–7.20 PJ (1.84-1.99 TWh) of local energy generation** (which can be met through renewable energy exports).
- **Scenario 2**: Meeting **10% of Germany's steel** demand in this scenario would require approximately **3.85 Mt of green iron** and **0.655–6.04 PJ (0.181-1.67 TWh) of local energy generation** (which can be met through renewable energy exports).
- **Scenario 3**: Meeting **10% of Germany's steel demand** under this scenario would require approximately **3.54 Mt** of green steel. Additional energy requirements would be needed to convert this steel to specialty steel products; however, these were not considered by this analysis.

Delivered costs (current cost estimates as of 2025[1]) were estimated for **ten potential production sites across Australia** to the **Port of Hamburg, Germany**. A summary of the delivered costs for renewable energy export costs is provided below.

Summary of Renewable Energy Delivered Costs

Renewable Energy Exports	A$/GJ
Liquefied Hydrogen	102-143
Liquid Organic Hydrogen Carrier (LOHC)	94-127
Ammonia	91-126
Liquefied Synthetic Natural Gas	91-124

[1] Note: All production cost estimates in this report reflect current (2025) input prices for renewable electricity, hydrogen, fossil fuels, and commodities. Refer to appendix for associated assumptions.

Similarly, the following table summarises the delivered costs of **iron ore, iron, and steel** from the **ten potential production sites across Australia** to the **Port of Hamburg, Germany**. Cost variations between the *Hematite Pathway* and *Magnetite Pathway* reflect the different processing requirements to produce iron and steel from hematite and magnetite ore.

Summary of Iron Ore, Iron and Steel Delivered Costs

Hematite Pathway	**Iron Ore[1] (A$/tonne)**	**Iron[2] (A$/tonne)**	**Steel (A$/tonne)**
Fossil Fuel Case	97-116	380-427	431-478
Green Case (Entire Value Chain Decarbonised)	184-256	832-1196	883-1255
Green Case (Only Iron and Steelmaking Decarbonised)	97-116	760-1037	812-1095
Green Case (Only Iron and Steelmaking Decarbonised) – Including A$2/kgH2 tax credit	97-116	636-913	688-971
Magnetite Pathway	**Iron Ore[1] (A$/tonne)**	**Iron[2] (A$/tonne)**	**Steel (A$/tonne)**
Fossil Fuel Case	123-140	299-349	432-486
Green Case (Entire Value Chain Decarbonised)	232-354	782-1147	934-1362
Green Case (Only Iron and Steelmaking Decarbonised)	123-140	663-896	812-1099
Green Case (Only Iron and Steelmaking Decarbonised) – Including A$2/kgH2 tax credit	123-140	539-772	688-975

1. In the *Hematite Pathway*, iron ore refers to **direct shipping ore (DSO)**, while in the *Magnetite Pathway*, iron ore refers to **DRI-grade iron ore pellets.**
2. In the *Hematite Pathway*, iron refers to a product similar to **pig iron**, while in the *Magnetite Pathway*, iron refers to **hot-briquetted iron (HBI).**

Importantly, when considering current port-side prices of iron and steel, **595 A$/tonne** for pig iron[1] and **515 A$/tonne** for HBI[2]—the delivered cost of **green iron and steel**, where only iron and steelmaking are decarbonised and a **$2/kg$_{H_2}$ tax credit** is applied, allows green iron to be produced **close to** market rates and green steel to be produced **at or below** current market rates.

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1 Establishing a Green Iron and Steel Value Chain between Australia and Germany

Australia can play three key roles in facilitating Germany's transition to low-carbon steelmaking.

This report forms the **third** part of a series of **four** reports examining the opportunities for establishing a green iron and steel value chain between Australia and Germany. By leveraging Australia's abundant renewable energy resources and mineral wealth, and Europe's advanced industrial capabilities, this partnership has the potential to drive significant progress in decarbonising the German steel industry.

As outlined in **Report 1**, through the development of renewable energy and the adoption of green ironmaking and steelmaking technologies, three key *value chain scenarios* are identified where Australia could contribute to advancing green steel production in Germany:

- **Scenario 1:** Export iron ore and renewable hydrogen (or derivatives) to Germany for green iron and steel production.
- **Scenario 2:** Produce green iron in Australia and exporting it, along with renewable hydrogen (or derivatives), to support green steel production in Germany.
- **Scenario 3:** Produce both green iron and green steel in Australia for export to Germany, where further processing into specialty steels would occur.

Noting that the **first two scenarios are most viable** under existing industry structures in Australia and Germany

Scope: The analysis assessed each scenario for meeting 1%, 10%, 25%, 50%, and 100% of Germany's steel demand, by evaluating a range of techno-economic and environmental metrics that include:

- **Capital investment requirements** (mine, plant, renewable generation, storage, transport infrastructure)
- **Operating costs** across all value chain stages (mining, transport, ironmaking, steelmaking, shipping)
- **Infrastructure needs** (rail, port, energy transmission, hydrogen production and storage capacity)
- **Renewable energy requirements** in PJ/TWh for electricity and hydrogen supply for decarbonising value
- **CO_2 emissions** (Scope 1 and 2) by process stage and pathway
- **Feedstock volumes** for ore, hydrogen, and derivatives
- **Delivered product costs** (iron ore, iron, and steel) from Australian production sites to Germany (Port of Hamburg)
- **Comparative costs** between Australian exports and German domestic green iron/steel production

Key Outcomes: The analysis finds

- **Lower cost vs. German domestic production**: Australian-produced green iron (magnetite HBI and hematite pig iron pathways) can be delivered to Germany at **A$539–772/t HBI** (with tax credit) or **A$636–913/t pig iron** (with tax credit), which is lower than the estimated **A$676–1,063/t iron** cost for German domestic green iron production from imported renewable hydrogen
- **Near-market parity under targeted decarbonisation**: When only iron and steelmaking are decarbonised and Australia's A$2/kg$H_2$ tax credit (HPTI) is applied:
  - Green iron can be produced at **A$539–772/t HBI** or **A$636–913/t pig iron**, close to parity with current portside prices (A$515/t HBI, A$595/t pig iron).
  - Subsequently, green steel can be produced at **A$688–975/**t, at or below current market prices **(~A$760/t** medium plate steel).
  - These are based on current (2025) estimated Australian renewable hydrogen costs of **~A$7.2–10.7/kg$H_2$** and renewable electricity costs of ~**A$155–299/MWh.** Significant deviations in these input costs—particularly hydrogen—would directly affect delivered green steel prices.
- **Competitive Advantage and Optimal Scenario**:
  - Locational competitiveness within Australia: **Geraldton, WA**, delivers advantages such as the lowest costs for green iron and green steel due to strong solar–wind complementarity (minimising requirements for energy storage needed for firming), and natural proximity to port. **Pilbara and Kwinana** also perform strongly despite higher labour costs in the Pilbara.
  - Best-performing scenario: **Scenario 2** (green iron export) via the magnetite HBI pathway under targeted decarbonisation with the A$2/kg$H_2$ tax credit offers the most substantial cost advantage relative to German domestic production **(reduces Germany's renewable hydrogen requirement by ~26 PJ/year, lowers delivered green iron costs by ~A$100–250/t, and cuts emissions by ~90% compared to current BAU BF–BOF production)**.
  - Source of cost advantage: The cost advantage is driven by Australia's abundant, high-quality iron ore resources and its strong solar–wind renewable energy profiles, which lower generation and storage costs compared to Germany's domestic production. These advantages create a natural synergy with Germany's advanced steelmaking technologies and high-value manufacturing capabilities, enabling a complementary value chain where Australia supplies competitive green iron feedstock and Germany adds value through processing into specialty steels and downstream products for domestic and export markets.

Evolving Analysis: While current modelling reflects today's renewable energy and hydrogen prices, future projections indicate significant declines in these costs, which would further improve the competitiveness of Australian green iron and steel in export markets. To enable continuous reassessment as market conditions evolve, all modelling tools developed in this project are being released as open-source resources.

2 Scenario Analysis and Site Selection

Ten locations across Australia were determined to assess the development of a green iron and steel value chain between Australia and Germany.

The following sections outline the different *value chain scenarios* that were assessed and the site locations across Australia.

2.1 Scenario Analysis

Each decarbonisation option was assessed with respect to the three different *value chain scenarios* outlined in **Section 1. Figure 1** illustrates the different configurations considered for each *value chain scenario*. The following **Section 3** outlines the framework used to assess each step of the value chain.

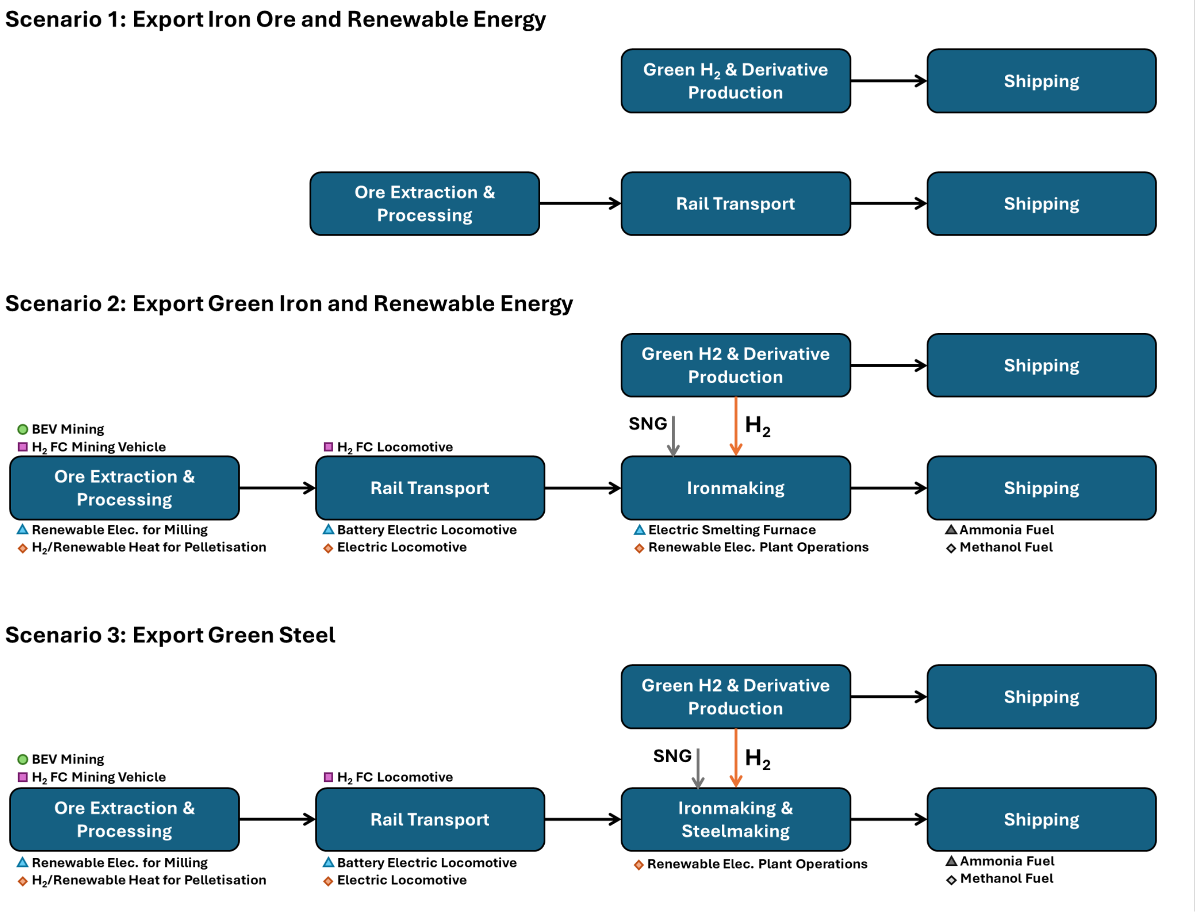


Figure 1. Implementation of the green steel value chain models for each scenario considered by this analysis. The figures represent the decarbonisation measures for each export scenario. In Scenario 1 (iron ore + renewable energy export), mining uses battery-electric or hydrogen fuel-cell vehicles, milling and pelletisation use renewable electricity or hydrogen heat, and rail/shipping use low-carbon locomotives and ammonia/methanol-fuelled vessels. In Scenario 2 (green iron + renewable energy export), these measures are combined with hydrogen-DRI or synthetic natural gas/SNG-DRI ironmaking powered by renewables before export. In Scenario 3 (green steel export), renewable-powered steelmaking (EAF or BOF, depending on ore type) is added to deliver fully decarbonised steel products alongside low-carbon transport.

2.2 Site Selection

The development of a large-scale, export-oriented green iron and steel value chain in Australia depends on access to abundant renewable energy, high-quality iron ore resources, efficient rail and port infrastructure, and sufficient human capital for construction and operation. As such, site selection prioritised locations near current announced hydrogen hubs [3], current iron and steel mills, and current green iron and steel project announcements (as detailed in **Report 1**), as these were assumed to meet the key requirements for developing a large-scale green iron and steel value chain. Based on these criteria, **ten locations** were identified across Australia, and are shown in **Figure 2**.

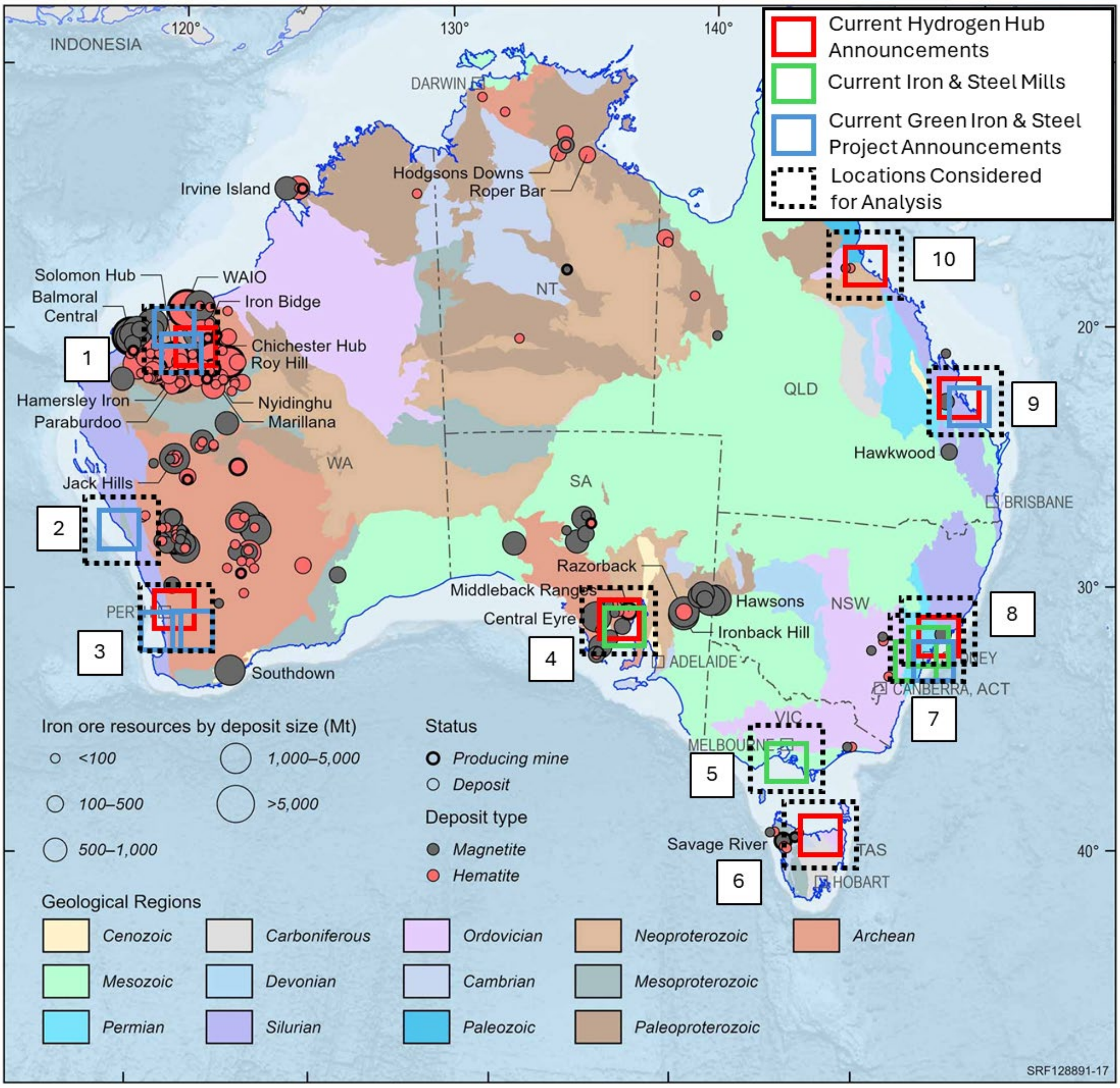


Figure 2. Map of Australian iron ore reserves overlayed with site selection criteria and locations considered for analysis. Base map of Australian iron ore reserves image sourced from Geoscience Australia [4], modified by the authors under the CC BY 4.0 license

Each of the ten identified locations was then evaluated against a Multi-Criteria Analysis (MCA) assessing their proximity to iron ore reserves, rail networks, port infrastructure and major cities (as a proxy for access to human capital) to rank the suitability of each location in developing a green iron and steel value chain. Each category was scored from 1 to 3, with 1 being the lowest and 3 the highest. An overview of the MCA framework and scoring methodology has been provided in **Appendix 1,** and the results of the MCA have been provided in **Table 1**.

Extraction – Green Mining & Transport:

Locations such as **Pilbara, WA**, **Geraldton, WA**, and **Whyalla, SA** are exceptionally well-positioned for large-scale, low-emissions mining operations. They have proximity to high-grade iron ore reserves, efficient rail connections, and established port infrastructure to support bulk ore transport. Pilbara and Geraldton leverage extensive ore bodies and mature export logistics, while Whyalla benefits from both major ore reserves and integrated transport links to processing facilities.

Processing – Conversion & Value Addition (Ironmaking & Steelmaking):

Sites such as **Gladstone, QLD**, **Newcastle, NSW**, **Port Kembla, NSW**, and **Bell Bay, TAS** excel in the infrastructure and resources required for hydrogen-based DRI/EAF production and steel value addition. These locations combine strong renewable energy potential (wind and/or solar), robust grid and transmission infrastructure, access to reliable water supplies, and proximity to skilled labour. Gladstone offers a unique combination of excellent renewable resources and deep-water port capacity, while Newcastle and Port Kembla provide strong industrial ecosystems and market access.

Overall:

Each of the ten identified locations ranked highly across most criteria, highlighting their suitability for contributing to a green iron and steel value chain. From an integrated green iron and steel value chain perspective, **Whyalla, SA** stands out as the most strategically positioned location, combining world-class ore reserves, efficient transport links, strong renewable energy resources, and established steelmaking facilities. Geraldton, WA and Gladstone, QLD also demonstrate strong potential—each excelling in one end of the chain (extraction for Geraldton, processing for Gladstone) while retaining the capacity to support the other through infrastructure and resource synergies. Other locations, such as Newcastle, NSW and Port Kembla, NSW, contribute significant processing and export capacity, complementing extraction hubs to form a distributed yet interconnected supply network. Even Townsville, QLD, despite ranking lowest overall due to smaller ore reserves, holds strategic value as a potential processing and export node leveraging its solar potential, industrial land, and port facilities. Collectively, these sites form the backbone of a nationally integrated, low-emissions iron and steel industry capable of servicing both domestic and export markets.

Table 1. Results of the MCA for identified locations

Location	Proximity to Iron Ore Reserves	Size of Closest Iron Ore Reserves	Proximity to High Quality Renewable Potential	Proximity to Electricity Infrastructure	Proximity to Water Resources	Proximity to Rail Networks	Proximity to Port Infrastructure	Proximity to Major Cities	Total Score	Rank
Pilbara, WA	3	3	3	3	3	3	3	1	21	3
Geraldton, WA	3	3	3	3	2	3	3	2	22	2
Kwinana, WA	2	2	3	3	2	3	3	3	20	4
Whyalla, SA	3	3	3	3	3	3	3	3	24	1
Melbourne, VIC	2	1	3	3	2	3	3	2	19	5
Bell Bay, TAS	3	2	3	2	2	3	3	2	20	4
Port Kembla, NSW	3	1	3	3	2	3	3	3	20	4
Newcastle, NSW	3	2	3	3	2	3	3	2	21	3
Gladstone, QLD	3	2	3	3	3	3	3	2	22	2
Townsville, QLD	3	1	3	2	1	3	3	2	18	6

3 Assessment Framework

An assessment framework was developed to assess the costs involved with decarbonising each aspect of a green iron and steel value chain. All models are being released as open-source tools as part of this work.

The following framework was developed to evaluate the establishment of a green iron and steel value chain between Australia and Germany. The framework considered each stage of the iron and steel value chain, including ore extraction & processing, rail transport, iron & steelmaking, and shipping, through a series of discrete models. Levelised costs and carbon emissions were determined for each stage, using in-house numerical models. This approach allowed for a comparison of the *current pathway technologies* with various *decarbonisation pathway technologies*, evaluating their impact on costs and carbon emissions across the value chain. Furthermore, **all models are being released as open-source tools as part of this work**.

As outlined in **Report 2**, although several green iron and steel decarbonisation technologies are currently under development, hydrogen-based direct reduced iron (H_2-DRI) paired with an electric arc furnace is often seen as the closest to commercialisation for achieving deep emissions reductions.[5,6] Additionally, **Report 1** highlights that many German steelmakers are transitioning from blast furnaces to natural gas-based DRI processes, with plans to transition to hydrogen-based DRI. For these reasons, this analysis focused on the use of DRI for iron and steelmaking. **Table 2** outlines the different decarbonisation technologies considered for each stage of the green iron and steel value chain. Findings from the German-led side of the feasibility study will provide further insights into the cost outlook for other process pathways.

Table 2. Decarbonisation technology options considered for each stage of the green iron and steel value chain

Stage of Value Chain	*Current Pathway Technologies*	*Decarbonisation Pathway Technologies*
Ore Extraction & Processing	Diesel-powered mining vehicles (drilling, loading and hauling)	Battery-electric mining vehicles
		Hydrogen fuel-cell mining vehicles
	Natural gas to provide thermal energy for pelletisation	Hydrogen to provide thermal energy for pelletisation
		Renewable electricity to provide thermal energy for pelletisation
	Fossil-fuel based electricity for ore milling and processing	Renewable electricity for ore milling and processing
Rail Transport	Diesel locomotive	Electric locomotive (powered by catenary lines)
		Battery electric locomotive
		Hydrogen fuel-cell locomotive
Ironmaking	Direct reduced iron (operating with natural gas)	Direct reduced iron (operating with hydrogen)
		Direct reduced iron (operating with synthetic natural gas)
	Electric smelting furnace[1] (operating with fossil-fuel based electricity)	Electric smelting furnace (operating with renewable electricity)
	Fossil-fuel based electricity for plant operation	Renewable electricity for plant operation
Steelmaking	Electric arc furnace[2] (operating with fossil-fuel based electricity)	Electric arc furnace (operating with renewable electricity)
	Basic oxygen furnace[2] (operating with fossil-fuel based electricity)	Basic oxygen furnace (operating with renewable electricity)
	Fossil-fuel based electricity for plant operation	Renewable electricity for plant operation
Shipping	Shipping vessels operating with heavy fuel oil (HFO)	Shipping vessels operating with low-carbon ammonia fuel
		Shipping vessels operating with low-carbon methanol fuel

1. As discussed in **Report 2**, the use of an electric smelting furnace can be coupled with a DRI process to enable operation with lower-grade ores, such as certain hematite ores, that cannot be easily beneficiated with current technologies.
2. As outlined in **Report 2**, an electric arc furnace is typically coupled with a DRI process for steelmaking. However, for instances where the DRI process is associated with an electric smelting furnace, a basic oxygen furnace is typically used for steelmaking.

3.1 Ore Extraction & Processing Model

The ore extraction & processing model evaluated the operation of an open pit mine, incorporating costs for ore processing plant, tailings dam storage and mining vehicle operation and procurement costs. Notably, there are distinct differences between the iron ore extraction and processing requirements for magnetite and hematite ores (and consequently iron and steelmaking processes for each ore type, as explored in **Section 3.4** and **3.5**). These differences arise from the ore quality and ability to beneficiate the ore, which is reflected in how the model was operated for each ore type.

Naturally occurring magnetite ore typically has a lower grade, 20–30% Fe, compared to Australian hematite direct shippable ore (DSO), 56–62% Fe. This is despite pure magnetite having a higher iron content (72.4% Fe) than pure hematite (69.9% Fe).[7] Consequently, iron ore beneficiation is commonly applied to magnetite ore to produce DRI-grade pellets for use in a DRI process, where its magnetic properties facilitate the use of magnetic separation for beneficiation.[8,9]

In contrast, hematite ore is weakly magnetic and cannot undergo the same beneficiation processes as magnetite ore. However, beneficiation techniques designed explicitly for hematite ores are being investigated by organisations like the Heavy Industry Low-carbon Transition Cooperative Research Centre (HILT-CRC) and the Commonwealth Scientific and Industrial Research Organisation (CSIRO).[10,11] This study assumes that beneficiation and pelletisation are only applied to magnetite ores. A schematic of the ore extraction & processing model has been provided in **Figure 3**.

For clarity, the two processing routes, owing to differences between magnetite and hematite ores, are referred to in this study as the ***Magnetite Pathway*** and the ***Hematite Pathway***, respectively.

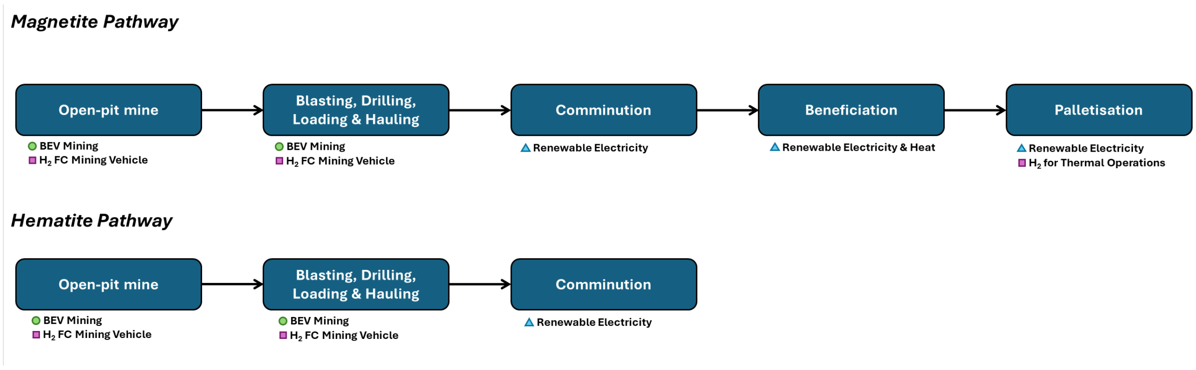


Figure 3. Ore Extraction & Processing Model Schematic. In the Magnetite Pathway, open-pit mining and material handling are electrified via battery-electric or hydrogen fuel-cell vehicles, followed by comminution powered by renewable electricity, beneficiation using renewable electricity and heat, and pelletisation using renewable electricity or hydrogen for thermal operations. In the Hematite Pathway, similar low-emission mining and hauling measures are applied, with comminution powered by renewable electricity; beneficiation is not included due to current limitations in processing hematite for DRI, reflecting pathway-specific processing requirements.

As outlined in **Table 2,** current pathway technologies for ore extraction and processing consider all mining vehicles (drilling, loading, and hauling) to be diesel-powered, and electricity for milling and processing is sourced from fossil fuels. For the magnetite ore pathway (which included beneficiation and pelletisation), natural gas was assumed to provide thermal energy for pelletisation. *Decarbonisation pathway technologies* assumed mining vehicles to be operated by hydrogen fuel-cell or battery electric drivetrains, reflecting the decarbonisation options currently being considered by the mining sector. [12-14], and thermal energy for pelletisation was assumed to be sourced from hydrogen[15] or electricity[16]. All electricity and hydrogen for the *decarbonisation technologies* were assumed to be derived from low-carbon, renewable sources. The processing plant was considered to operate with a process availability of 90%. A detailed summary of the CAPEX and OPEX estimates of the ore extraction & processing model has been provided in **Appendix 2**. It includes the methodology used to estimate hydrogen fuel-cell and battery-electric vehicle costs and renewable energy requirements.

3.2 Rail Transport Model

The rail transport model assumed the use of existing rail-line infrastructure, accounting for locomotive and wagon operation and procurement costs. In each location, the ironmaking and steelmaking facilities were considered to be located close to the port, meaning that rail transport was needed for the transport of ore from the mine site location to the ironmaking or steelmaking facilities only. A schematic of the rail transport model has been included in **Figure 4**.

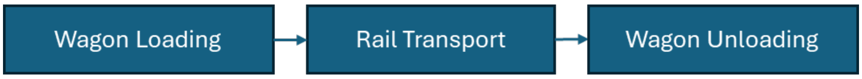


Figure 4. Rail Transport Model Schematic

Current pathway technologies assumed locomotives to be diesel-powered, and *decarbonisation pathway technologies* assumed locomotives to either be electric (powered by overhead catenary lines), battery-electric, or powered by hydrogen fuel cells. These options were considered as they are widely recognised as viable decarbonisation solutions for rail freight.[13,17,18] All electricity and hydrogen for the decarbonisation technologies were assumed to be derived from low-carbon, renewable sources (**Table 2**). A summary of the CAPEX and OPEX assumptions for the rail transport model is provided in **Appendix 3**.

3.3 Shipping Model

The shipping model was used to model two aspects of the value chain. The first modelled the export of iron ore, iron and steel products. The second modelled the export of renewable energy in the form of hydrogen and its derivatives.

Iron ore, Iron and Steel Export

The shipping model assumed the use of existing port infrastructure, accounting for ship operation and procurement costs. A schematic of the shipping model has been included in **Figure 5**.

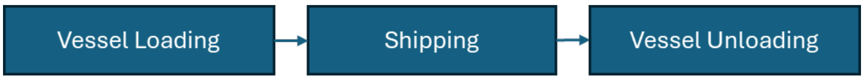


Figure 5. Shipping Model Schematic

Current pathway technologies assume shipping vessels to operate on heavy fuel oil (HFO), *decarbonisation pathway technologies* assume shipping vessels to operate on low-carbon ammonia or methanol (**Table 2**), as these are two widely recognised decarbonisation options for shipping.[12,19] Shipping assumed that iron ore and iron were exported as dry-bulk cargo [20,21], while steel was exported as break-bulk cargo.[22] A summary of the CAPEX and OPEX assumptions for the shipping model is provided in **Appendix 4**.

Renewable Energy Export

The shipping of renewable energy (in the form of hydrogen and its derivatives) was modelled based on our group's previous work [23], using the HySupply Shipping Analysis Tool V1.1.[24] Assumptions used in the shipping model have been included in **Appendix 5**.

3.4 Ironmaking Model

The ironmaking model assumed the development of a new production site, including operational and procurement costs. A schematic of the ironmaking model has been provided in **Figure 6**. As highlighted in **Section 3.1**, there are differences between the ironmaking requirements for magnetite and hematite ores, the two major ore types mined in Australia. These differences arise from the ore quality and ability to beneficiate the ore, leading to differences in how these ores are currently mined and processed.

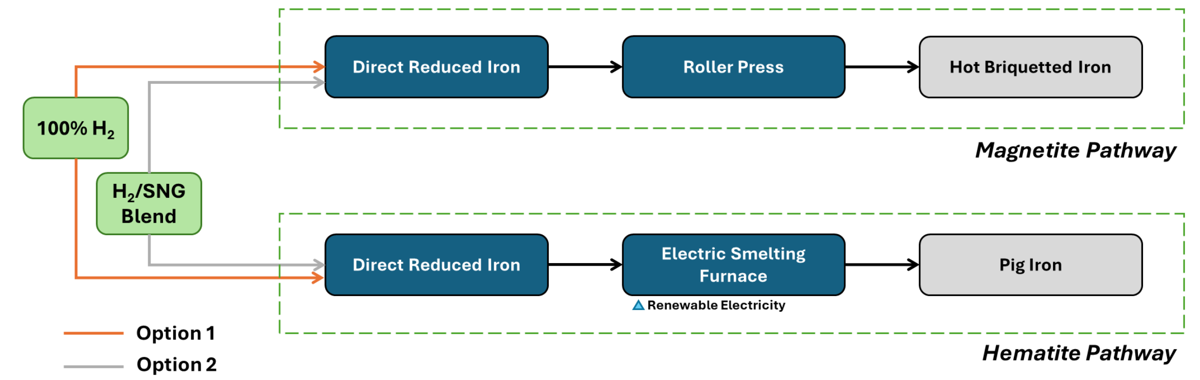


Figure 6. Ironmaking Model Schematic. In the Magnetite Pathway, beneficiated ore is reduced via hydrogen-based or hydrogen/synthetic natural gas (SNG) blend DRI, producing sponge iron which is roller-pressed into hot briquetted iron (HBI) for safe transport. In the Hematite Pathway, lower-grade DRI undergoes further refining in a renewable electricity-powered electric smelting furnace (ESF) to remove impurities, producing pig iron. Both pathways offer two fuel options for the DRI stage: Option 1 – 100% renewable hydrogen; Option 2 – a transitional hydrogen/SNG blend enabling gradual decarbonisation while utilising existing natural gas infrastructure.

When beneficiated magnetite ore is converted to DRI, the resulting product is of sufficient quality for direct use in steelmaking. However, as discussed in **Report 2**, the DRI process produces porous iron pellets, known as sponge iron [25], which are highly reactive to air and moisture and prone to combustion [26]. To ensure safer storage and transport, DRI intended for sale as an intermediate product is typically converted into hot-briquetted iron (HBI) through an additional processing step.

In contrast, hematite ore cannot currently be beneficiated in the same way as magnetite ore (although beneficiation processes for hematite are under development, as noted in **Section 3.1**). As such, DRI produced from lower-grade hematite ore contains too many impurities, which make it unsuitable for direct use in steelmaking. In such cases, as outlined in **Report 2**, an electric smelting furnace is used to upgrade the DRI to a product suitable for steelmaking. The output from an electric smelting furnace is a product similar to pig iron (for simplicity, **referred to herein as pig iron**) and does not require conversion to HBI for shipping or transport.

As outlined in **Table 2**, the *current pathway technologies* considered the natural gas-based direct reduced iron (NG-DRI) process, which uses syngas (derived from natural gas) as a reducing agent and fossil fuel-based electricity for plant operations. The *decarbonisation pathway technologies* focused on the direct reduced iron (DRI) process using hydrogen gas as a reducing agent. Additionally, as DRI processes are currently being implemented in Germany and Australia, initially operating on natural gas with plans to transition to hydrogen gas (as discussed in **Report 1**), this analysis also considers the use of DRI operating on synthetic natural gas. This approach provides immediate CO_2 reductions with the use of existing natural gas infrastructure, as well as potentially offering operational benefits as an export vector from Australia to Germany over hydrogen or other hydrogen derivatives. All electricity for plant operation, hydrogen and hydrogen derivatives for the *decarbonisation pathway technologies* were assumed to be derived from low-carbon, renewable sources (**Table 2**). The ironmaking plant was assumed to operate with a process availability of 90%. A summary of the CAPEX and OPEX assumptions for the ironmaking model, as well as a more detailed process schematic for the ironmaking process, is provided in **Appendix 6**.

3.5 Steelmaking Model

Steelmaking can either be performed as a standalone process from ironmaking, where iron is produced at another facility and used to produce steel at a standalone steel mill. This involves the need to produce intermediate iron products such as HBI and pig iron, as described in **Section 3.4**, which can then be transported to the steelmaking facility.

Alternatively, steelmaking can be performed as an integrated process, where iron and steelmaking are conducted within the same facility. This arrangement allows for the intermediate iron product to be used directly in the steelmaking process, maintaining residual heat in the intermediate product and improving overall process efficiency. For the *Magnetite Pathway*, this removes the need for HBI production, while for the *Hematite Pathway*, it eliminates the need for casting pig iron.

Similar to the ironmaking model, the steelmaking model assumed the establishment of a new production site, including operational and procurement costs. A schematic of the steelmaking model, based on an integrated steel mill, has been provided in **Figure 7.**

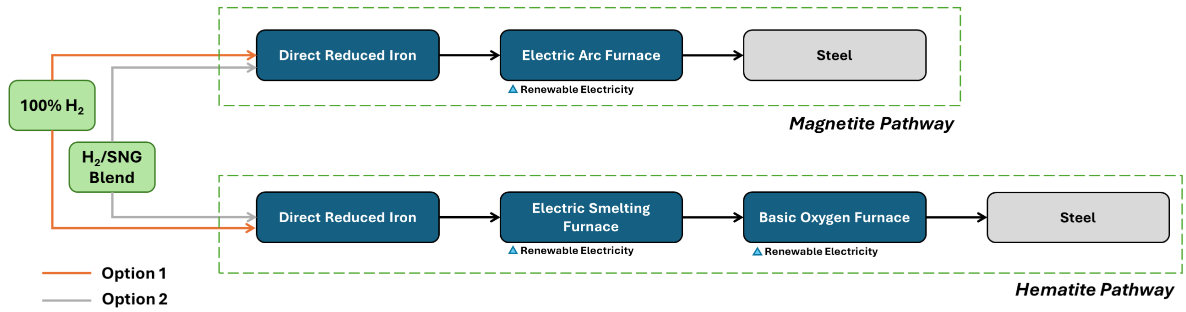


Figure 7. Steelmaking Model Schematic. In the Magnetite Pathway, hydrogen-based or hydrogen/SNG blend DRI is fed directly into a renewable electricity-powered electric arc furnace (EAF) to produce steel. In the Hematite Pathway, lower-grade DRI is first refined in a renewable electricity-powered electric smelting furnace (ESF) to remove gangue and adjust composition, before being converted to steel in a renewable electricity-powered basic oxygen furnace (BOF). Both pathways incorporate two fuel options for the DRI stage: Option 1 – 100% renewable hydrogen; Option 2 – a transitional hydrogen/SNG blend enabling phased decarbonisation while leveraging existing natural gas infrastructure.

As outlined in **Section 3.4**, there are differences between the use of magnetite and hematite ores for steelmaking, owing to challenges in beneficiating hematite ores. As such, the steelmaking model considers slightly different process pathways for each ore type, accounting for the fact that DRI from beneficiated magnetite ore can be used directly in an electric arc furnace for steelmaking. In contrast, DRI from lower-grade hematite ores first requires refining in an electric smelting furnace prior to being converted to steel in a basic oxygen furnace.

Similar to the ironmaking process (**Section 3.5**), the *current pathway technologies* for steelmaking considered the natural gas-based direct reduced iron (NG-DRI) process, and the *decarbonisation pathway technologies* considered all electricity for plant operation and hydrogen and hydrogen derivatives for the ironmaking step to be derived from low-carbon, renewable sources (**Table 2**). The iron and steelmaking plant was assumed to operate with a process availability of 90%. A summary of the CAPEX and OPEX assumptions for the steelmaking model, as well as a **more detailed process schematic for the steelmaking process,** is provided in **Appendix 7**.

3.6 Renewable Energy Generation Models

Renewable energy generation was assumed to be produced from solar PV and wind, as these technologies are amongst the lowest cost sources of renewable electricity and are predicted to meet 70% of global electricity generation by 2050.[25] Solar and wind potential were determined using Renewables Ninja [26-28] which provides hourly solar and wind traces for each location. Simulations were based on solar and wind traces for the year 2023.

Renewable Electricity Generation

Renewable electricity generation was assumed to be produced close to the corresponding site locations identified in **Section 2.** Systems assumed the operation of solar and wind hybrid generation, firmed with lithium-ion battery storage. A schematic of the renewable electricity generation model has been provided in **Figure 8**.

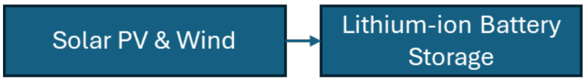


Figure 8. Renewable Electricity Generation Model Schematic

For each location, systems were optimised based on the relative proportions of solar and wind generation, generation overcapacity, and battery storage duration to give a minimum system capacity factor of **90%.** The system configuration that achieved this capacity factor for the lowest cost was selected for each location. A summary of the CAPEX and OPEX assumptions for renewable electricity generation is provided in **Appendix 8.1**.

Renewable Hydrogen Generation

Renewable electricity generation was assumed to be produced close to the corresponding site locations identified in **Section 2**. Hydrogen production is assumed to utilise alkaline electrolysers operated in conjunction with solar and wind hybrid generation and lithium-ion battery storage. Additionally, hydrogen can be produced from proton exchange membrane (PEM) electrolysers, which offer potential advantages in terms of faster response times and better integration with variable renewable energy sources.

For each location, hydrogen generation systems were optimised based on the relative proportions of solar and wind generation, generation overcapacity, and battery storage duration to give the system configuration that provided the minimum cost of hydrogen. Unlike renewable electricity generation, these systems were not constrained by a minimum capacity factor, as it was assumed that hydrogen could be compressed and stored on-site for downstream use. A schematic of the renewable electricity generation model has been provided in **Figure 9**.

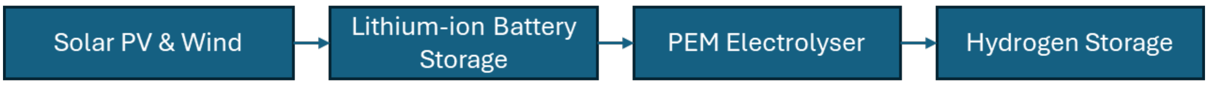


Figure 9. Renewable Hydrogen Generation Model Schematic

A summary of the CAPEX and OPEX assumptions for renewable hydrogen generation is provided in **Appendix 8.2**.

Hydrogen Derivatives Generation

Hydrogen derivatives were used in this analysis for two primary purposes: the first was for the export of renewable energy as part of the three scenarios outlined in **Section 2.1**, the second was for domestic use in iron and steelmaking, as well as low-carbon bunker fuels for shipping, as outlined in **Table 2**. For each derivative, processes were assumed to operate with a process availability of 90%, using firmed renewable energy and stored hydrogen.

For the export of renewable energy, this analysis considered the following four hydrogen derivatives: **ammonia, liquefied synthetic natural gas, liquid organic hydrogen carrier (LOHC),** where toluene-methylcyclohexane (MCH) used as the LOHC **and liquefied hydrogen**.[29] These vectors were selected because they can directly be used to produce hydrogen gas for hydrogen-based ironmaking, or, in the case of synthetic natural gas, for natural gas-based ironmaking. Although LOHC and liquefied hydrogen are technically not hydrogen derivatives, they have been included here as they represent additional capital and operating expenditure to convert gaseous hydrogen into a form that can be transported long distances.

For each energy vector, modelling includes the reconversion costs associated with converting the vector back to a usable form for iron and steelmaking at the import terminal. For ammonia, this included the cracking of ammonia back to hydrogen; for LOHC, this included the recovery of hydrogen from the organic carrier; and for liquefied hydrogen, this included the regassification of hydrogen. As described in **Report 2**, the natural gas-based DRI process uses syngas as a reducing agent, derived from natural gas. However, this is a conversion step that occurs at the point of use at the ironmaking and or steelmaking facility and has hence been accounted for in the natural gas-based ironmaking and steelmaking models. As such, only the regassification of liquefied synthetic natural gas was accounted for in these models.

For hydrogen derivatives that were produced for domestic use, such as synthetic natural gas, renewable ammonia and renewable methanol, all derivatives were assumed to be made close to the corresponding site locations identified in **Section 2**. Any hydrogen and electricity used in the production of these derivatives were assumed to be generated by the renewable hydrogen and electricity models described above. Ammonia production was based on the Haber-Bosch process, with nitrogen sourced from cryogenic air separation. Methanol and synthetic natural gas production were assumed to follow the methanation and methanol synthesis processes, respectively, using CO_2 sourced from biogenic sources.[29] A schematic of each of the hydrogen derivatives generation models has been provided in **Figure 10**.

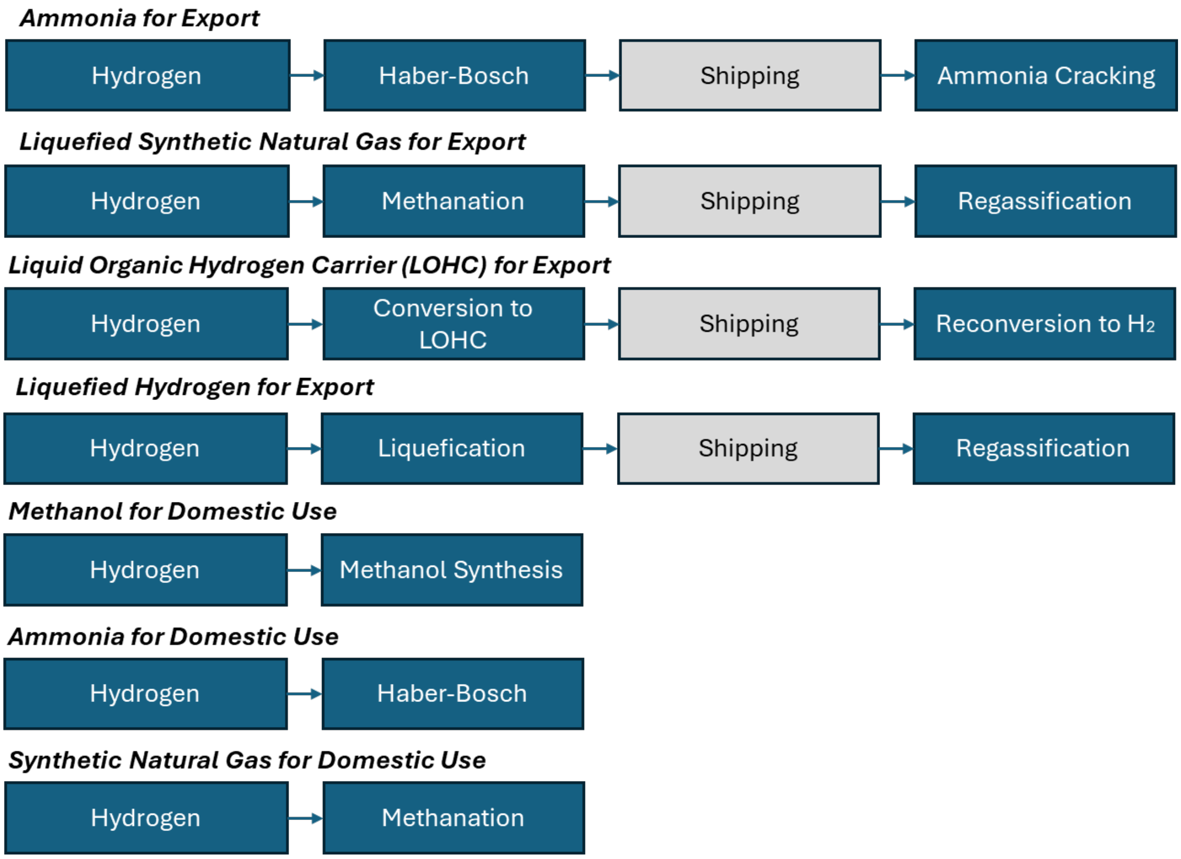


Figure 10. Hydrogen Derivatives Generation Model Schematic. Shipping steps for export have been coloured in grey to signify that these are not included in the hydrogen derivatives model, however, these steps occur before each of the respective reconversion steps.

A summary of the CAPEX and OPEX assumptions for hydrogen derivative generation is provided in **Appendix 8.3-8.7**.

3.7 Economic Assessment

For each model, the levelised cost was estimated based on the annual process output for each aspect of the value chain, along with estimates of annual capital and operating costs, as shown below:

$$\textbf{Levelised Cost} = \frac{\text{CRF} \times \text{Capital Cost } + \text{Annual Operating Costs}}{\text{Annual Process Output}} \tag{1}$$

Here, CRF is the capital recovery factor, and the CRF is used to annuitise the capital cost and distribute it into a present value of returns needed to recover the capital costs.

The CRF was calculated as a function of the weighted average cost of capital (WACC) and project lifetime, as shown below:

$$\textbf{CRF}\ (\%) = \frac{\text{WACC} \times (1 + \text{WACC})^{\text{n}}}{(1 + \text{WACC})^{\text{n}} - 1} \tag{2}$$

Here, n represents the expected economic (financing) lifetime of the project in years.

A **WACC of 7%** was applied uniformly across the value chain. However, since project lifespans vary for each stage of the value chain, different project lifespans were estimated for each stage and have been provided in the corresponding **Appendix 2-8** for each of the models outlined in **Sections 3.1-3.6.**

To account for economies of scale, a scale index was used to adjust costs from the reference capacity to the capacity applied in the model. The method estimates the cost at a new capacity (C_b) and scale (S_b) by scaling up or down the reference cost (C_a) at the reference scale (S_a) against a scale factor (f). All scale factors were provided alongside all CAPEX and OPEX assumptions for each model in the corresponding **Appendix 2-8** for each of the models outlined in **Sections 3.1-3.6.**

$$C_b = C_a \times \left(\frac{S_b}{S_a}\right)^f \tag{3}$$

All models have been developed as open-source tools, with the intention to be used not only in Australia, but globally. As such, all cost inputs to the models have been expressed in United States dollars (US$) for international relevance. However, as the results of this report pertain to the development of a green iron and steel value chain in Australia, all modelling results have been expressed in Australia dollars (A$) unless otherwise stated. To ensure clarity, the applicable currency is explicitly stated alongside any monetary values. Any currency conversions from Euro (€) or United States dollars (US$) to Australian dollars (A$) assumed an exchange rate of 0.7 (US$: A$ or € : A$).

3.8 Emissions Analysis

Scope 1 and 2 emissions, expressed in CO_2-equivalents (CO_2eq), were calculated based on operational inputs and energy consumption data for each stage of the value chain. Scope 1 emissions, which include direct emissions from on-site fossil fuel combustion (e.g., diesel used in mining vehicles and natural gas in processing facilities), were determined using activity data (e.g., fuel consumption) and emission factors. Scope 2 emissions, encompassing indirect emissions from purchased electricity, were estimated by applying grid emission factors specific to the location of operations. For scenarios involving renewable electricity, scope 2 emissions were assumed to be negligible. In each instance, scope 3 emissions, representing indirect emissions from upstream and downstream activities, were not included in this analysis.

An example of how the emissions factors were applied is provided below:

$$\begin{aligned}&\textbf{Greenhouse Gas Emissions } (\mathbf{kg\ CO_2e})\\ &\qquad = \text{Activity Data (kWh or kg)} \times \text{Emissions Factor} \left(\frac{\text{kg CO}_2\text{e}}{\text{kWh or kg}}\right) \quad (3)\end{aligned}$$

Where possible, emissions factors were obtained from the Department of Climate Change, Energy, Environment and Water (DCCEEW) National Greenhouse Accounts Factors [30], which estimates CO_2-equivalents based on a combination of the 100-year Global Warming Potential (GWP) of carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) emissions. A summary of the emissions factors assumed for the analysis has been provided in **Appendix 9**.

3.9 Geospatial Analysis

A geospatial analysis was performed to assess the relative costs of developing a green iron and steel value chain between Australia and Germany from each of the regions identified in **Section 2.2**. Notably, stakeholder discussions have highlighted some challenges involved with doing business in the Pilbara region, in part, owing to the high wages of current workers in the area. As such, variations between labour costs have been considered, in addition to geographic differences such as transport distances and renewable energy generation potential.

As discussed in **Report 2**, there are differences between the ironmaking and steelmaking requirements for magnetite and hematite ores, the two major ore types mined in Australia. These differences arise from the ore quality and ability to beneficiate the ore, leading to differences in how these ores are currently mined and processed. For this analysis, both hematite and magnetite process pathways were considered for each location, despite certain sites being in closer proximity to hematite or magnetite reserves (as shown in **Figure 2**, **Section 2.2**).

The following **Table 3** provides an overview of the input assumptions that varied between each location. All other cost inputs were assumed to be constant between locations and have been outlined in **Appendix 10**.

Table 3. Location-specific modelling assumptions

Input Costs	Units	Location 1 (Pilbara, WA)	Location 2 (Geraldton, WA)	Location 3 (Kwinana, WA)	Location 4 (Whyalla, SA)	Location 5 (Melbourne, VIC)	Location 6 (Bell Bay, TAS)	Location 7 (Port Kembla, NSW)	Location 8 (Newcastle, NSW)	Location 9 (Gladstone, QLD)	Location 10 (Townsville, QLD)	Average-case Values[1]	Notes and Assumptions
Grid Electricity	US$/MWh	81	81	81	81	70	74	95	95	88	88	83	Prices based on average wholesale market price for 2024 from Australian Energy Market Operator (AEMO) [31,32]. Each price includes an additional 35 A$/MWh to account for retail and transmission costs [33]
	A$/MWh	115	115	115	115	100	105	135	135	125	125	119	
Renewable Electricity	US$/MWh	128	109	109	127	180	160	199	209	147	154	152	Renewable electricity costs determined using methodology outlined in **Section 3.6**
	A$/MWh	183	155	156	182	258	228	285	299	210	219	217	
Natural Gas	US$/GJ	5.6	5.6	5.6	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	Australian east cost gas prices from Australian Energy Regulator (AER) [34]. Western Australian gas price based on Santos west coast gas price [35]
	A$/GJ	8	8	8	12	12	12	12	12	12	12	12	
Renewable Hydrogen	US$/$kg_{H2}$	5.8	5.1	5.1	5.8	6.6	6.0	7.5	7.5	6.2	6.5	6.2	Renewable hydrogen costs determined using the methodology outlined in **Section 3.6**
	A$/$kg_{H2}$	8.3	7.2	7.3	8.2	9.4	8.6	10.7	10.7	8.9	9.3	8.9	
Rail Distance	km	500	300	500	250	300	200	150	100	100	100	250	Approximate rail distance measured between the nearest ore deposit (as shown in **Figure 2**, **Section 2.2**) and the closest port for each location.
Shipping Distance	NM	9,714	9,694	9,837	11,068	11,364	11,440	11,778	11,878	12,006	11,599	11,038	Distances determined using sea distances.[36] Shipping distance for each location calculated between the nearest Australian port and the Port of Hamburg, Germany.
Labour Costs	US$/hr	60	36	36	36	36	36	36	36	36	36	36	Based on average national wages from OECD estimates. [37] Wages in the Pilbara increased by 70% compared to other locations to represent the higher wages due to remote work for this region.[33]
	A$/hr	86	51	51	51	51	51	51	51	51	51	51	

1. Average-case column includes a combination of average values and representative values. Average-case values used for the development of **Figure 11** and **Figure 17**

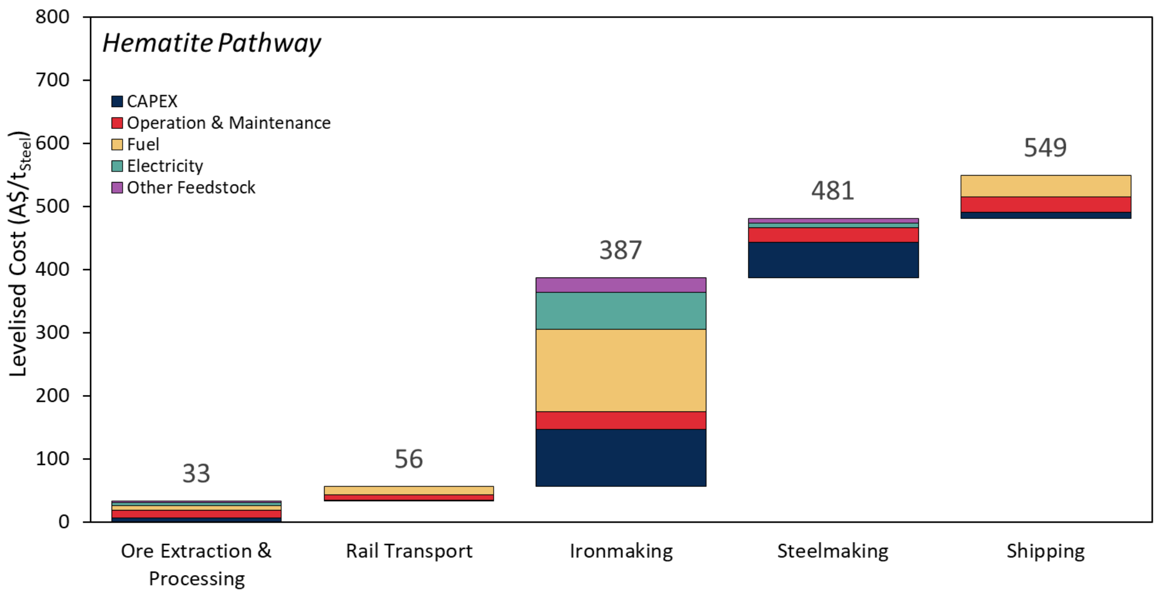
4 Fossil Fuel-based Iron and Steel Value Chain

Energy (fuel and electricity) is the most significant cost driver in iron and steel production, comprising 47% of delivered costs in the *Hematite Pathway* and 51% in the *Magnetite Pathway*. Natural gas in the ironmaking step is the most significant single contributor, accounting for 24% of total costs in both pathways.

The following sections provide an overview of costs and emissions in the development of an iron ore, iron and steel value chain using current fossil fuel-based technologies. As outlined in **Section 3**This analysis focuses on direct reduced iron (DRI) for ironmaking, with different processing requirements for magnetite and hematite ores due to challenges in beneficiating hematite ore. Results are presented for the *Hematite Pathway* and the *Magnetite Pathway* to represent costs associated with using the two different ore types.

4.1 Fossil Fuel-based Iron and Steel Value Chain Costs

The following **Figure 11** provides a breakdown of the levelised costs associated with the development of an iron and steel value chain between Australia and Germany. Values were expressed in cost per tonne of delivered steel.



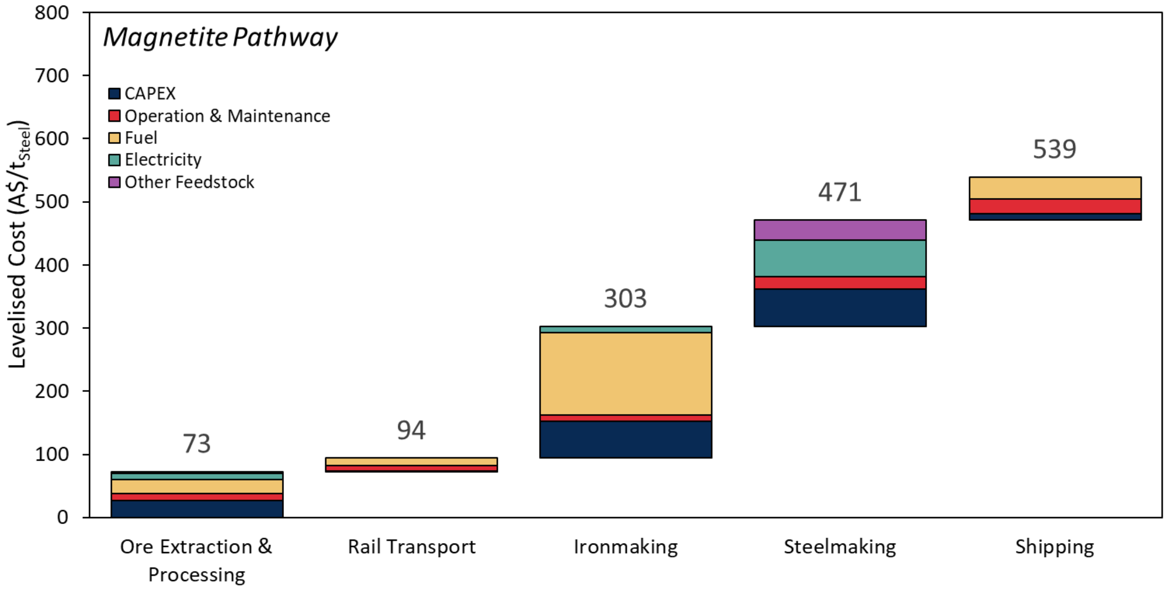


Figure 11. Levelised costs break-down for a fossil-fuel based iron and steel value chain between Australia and Germany. Analysis assumes a mine capacity of 5 Mtpa, an iron and steel mill capacity of 1 Mtpa, and maximum annual deliverable rail and shipping volumes. The Magnetite Pathway uses DRI-grade iron ore pellets and produces Hot Briquetted Iron (HBI), while the Hematite Pathway uses Direct Shippable Ore (DSO) to produce and iron product similar to pig iron. Both pathways produce steel slab with iron and steelmaking modelled as independent facilities. Plot generated using average-case values for 10 Australian production sites considered (See **Section 3.9** for details). Values were expressed per tonne of delivered steel, adjusted using an Fe content of 60%, 65%, 90% and 98% for DSO, iron ore pellets, iron and steel respectively.

Each aspect of the value chain was modelled independently, showing the levelised cost of production at each step. Furthermore, ironmaking and steelmaking were modelled as standalone processes, showcasing the costs associated with each conversion step if they were operated as independent plants, and includes casting costs for each the ironmaking and steelmaking steps.

Both pathways are estimated to result in the following delivered steel costs: **A\$549/tonne$_{Steel}$** for the *Hematite Pathway* and a slightly lower **A\$539/tonne$_{Steel}$** for the *Magnetite Pathway*. The *Magnetite Pathway* incurs higher iron ore production costs due to the need for **beneficiation and pelletisation** to make the ore suitable for steelmaking in the Direct Reduced Iron – Electric Arc Furnace (DRI-EAF) pathway. In contrast, hematite ore is not easily beneficiated (as discussed in **Section 3.1**), meaning that DRI produced via the *Hematite Pathway* must first be processed in an electric smelting furnace (ESF) to remove excess gangue before conversion to steel in a basic oxygen furnace (BOF). This results in an additional ironmaking step for hematite ore, leading to higher ironmaking costs for the Hematite Pathway compared to the Magnetite Pathway. However, this increase in cost is offset by the lower steelmaking costs associated with using a BOF instead of an EAF in the Hematite *Pathway*.

Importantly, energy (electricity and fuel) plays a critical role in determining production costs in the iron and steel industry, accounting for **47%** of delivered costs in the *Hematite Pathway* and **51%** in the *Magnetite Pathway*. Among these, natural gas used in the ironmaking process is the most significant single cost component, representing **24%** of total costs in both pathways.

4.2 Carbon Emissions

The following **Figure 12** outlines the carbon emission associated with a fossil-fuel-based iron and steel value chain from Australia to Germany. Similar to **Figure 11**, each aspect of the value chain was modelled independently, showing the tonnes of CO_2-eq for each product at each step in the value chain. Values were expressed in terms of delivered steel.

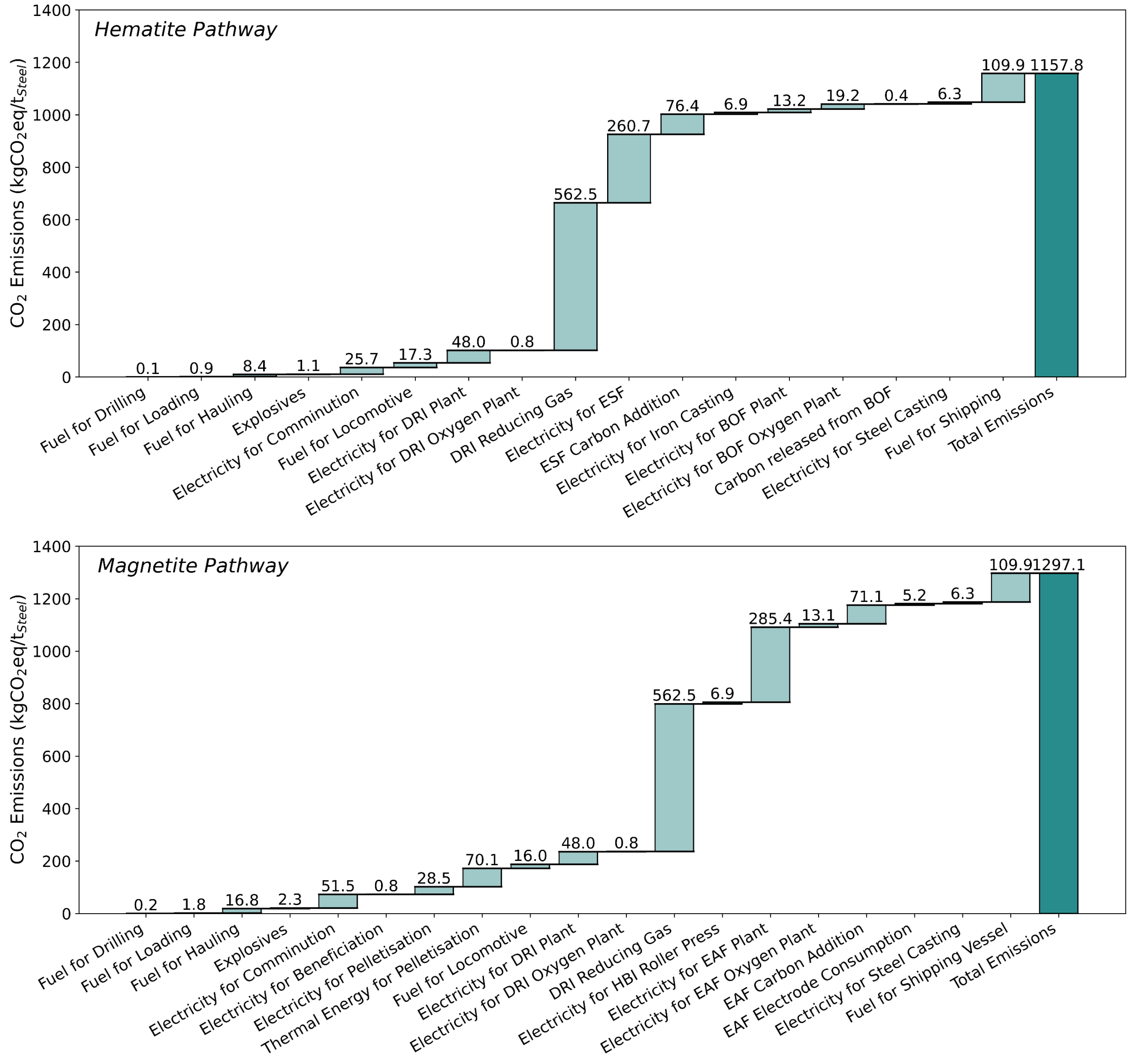


Figure 12. $CO_{2\text{-eq}}$ Emissions Breakdown Across a Fossil-fuel-Based Iron and Steel Value Chain between Australia and Germany. Analysis assumes a mine capacity of 5 Mtpa, an iron and steel mill capacity of 1 Mtpa, and maximum annual deliverable rail and shipping volumes. The Magnetite Pathway uses DRI-grade iron ore pellets and produces Hot Briquetted Iron (HBI). In contrast, the Hematite Pathway uses Direct Shippable Ore (DSO) to make an iron product similar to pig iron. Both pathways produce a steel slab with iron and steelmaking modelled as independent facilities. Plot generated using average-case values for 10 Australian production sites considered (See **Section 3.9** for details). Values were expressed per tonne of delivered steel, adjusted using an Fe content of 60%, 65%, 90% and 98% for DSO, iron ore pellets, iron and steel, respectively.

The total emissions per delivered steel are estimated at: **1,158 $kgCO_2$-eq/t_{Steel}** for the *Hematite Pathway* and a slightly higher **1,297 $kgCO_2$-eq/t_{Steel}** for the *Magnetite Pathway*. Across both pathways, the largest source of emissions arises from the reducing gas used in the ironmaking DRI process, accounting for **48.6%** and **43.4%** of the total emissions for the *Hematite* and *Magnetite Pathways,* respectively.

Notably, the *Magnetite Pathway* exhibits slightly higher emissions from drilling, loading, hauling, and comminution compared to the *Hematite Pathway*. This is because naturally occurring magnetite ore typically has a lower grade (20–30% Fe) compared to Australian DSO hematite ore (56–62% Fe),[7] as discussed in **Section 3.1**. As a result, more ore must be processed to produce the same amount of metallic iron.

Up to 93% of these emissions from both the *Hematite Pathway* and *Magnetite Pathway* can be mitigated through the decarbonisation options considered in **Table 2**, **Section 3**. The remaining 7% of emissions, stemming from the use of explosives in the mining of iron ore, carbon addition in ESF and EAF processes, and EAF electrode consumption, were not addressed in this analysis.

For reference, considering the ironmaking and steelmaking processes only, the *Hematite Pathway* generates an estimated **955 $kgCO_2$-eq/t_{Steel}** and **39.1 $kgCO_2$-eq/t_{Steel}** for the ironmaking and steelmaking processes, respectively. Similarly, the *Magnetite Pathway* generates an estimated **618 $kgCO_2$-eq/t_{Steel}** and **381 $kgCO_2$-eq/t_{Steel}** for ironmaking and steelmaking, respectively. In contrast, the conventional blast furnace–basic oxygen furnace (BF-BOF) process emits **1476 $kgCO_2$-eq/t_{Steel}** for ironmaking and **39.1 $kgCO_2$-eq/t_{Steel}** for steelmaking (see footnote[2]). This translates to an emissions reduction of **34.4%** in the *Hematite Pathway* and **46.2%** in the *Magnetite Pathway* for iron and steelmaking combined, compared to the conventional BF-BOF process route, if operating these pathways using conventional, fossil-fuel-based technologies.

[2] Blast furnace emissions of 1476 $kgCO_2$-eq/t_{Steel} based on analysis of Fan *et al.* [38], and omits emissions due to coke production and sintering of iron ore fines. Basic oxygen furnace emissions assumed to be similar to the BOF emissions from the *Hematite Pathway* as estimated by this analysis.

4.3 Location-Specific Cost Estimates

An overview of the costs associated with the production of iron ore, iron and steel in Australia for export to the Port of Hamburg (Germany) is provided in **Figure 13**. Analysis was performed for a value chain based on fossil fuels and current grid electricity (*Fossil Fuel Case*). Costs are expressed per tonne of the delivered product—iron ore per tonne of iron ore, iron per tonne of iron, and steel per tonne of steel. A production capacity of **1 Mtpa** was assumed for iron and steelmaking. In contrast, a **5 Mtpa** capacity was assumed for mining, reflecting the typically larger scale of iron ore mining operations compared to iron and steelmaking. Notably, these results are indicative, and a more detailed analysis should be conducted for specific locations as needed.

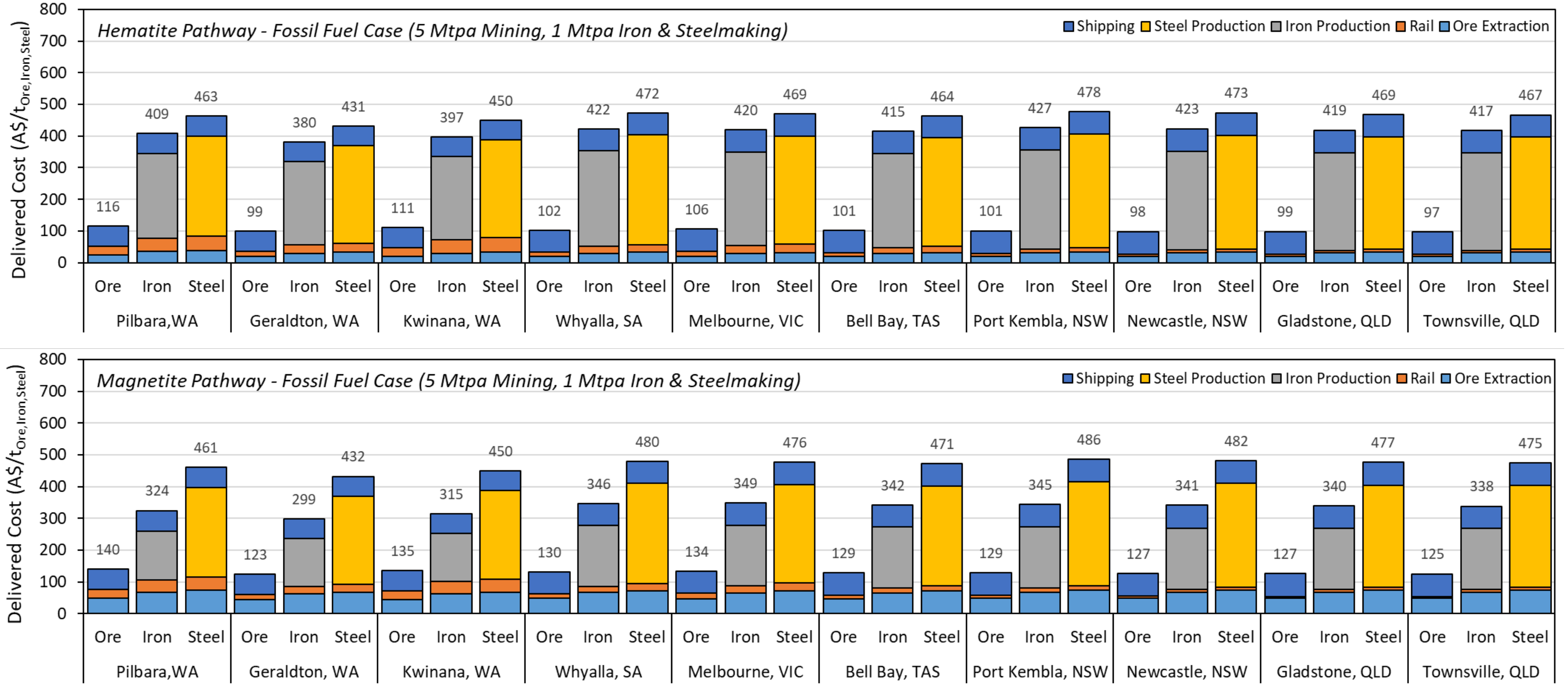


Figure 13. Delivered cost of iron ore, iron and steel from Australia to Germany using current fossil fuel-based technologies. Analysis based on a mine site capacity of **5Mtpa** and an iron and steel mill capacity of **1Mtpa**, with rail and shipping operations assuming maximum deliverable volumes per annum. Iron ore export in the Hematite Pathway refers to the export of Direct Shippable Ore (DSO), whereas iron ore export in the Magnetite Pathway refers to the export of DRI-grade iron ore pellets. Iron export in the Hematite Pathway refers to the export of an iron product similar to pig iron, and iron export in the Magnetite Pathway refers to the export of Hot Briquetted Iron (HBI). Steel in both pathways refers to the export of steel slab. The steelmaking process was assumed to operate as an integrated steel mill, with both ironmaking and steelmaking conducted at the same facility. Values were expressed per tonne of delivered product, adjusted using an Fe content of 60%, 65%, 90% and 98% for DSO, iron ore pellets, iron and steel respectively.

Differences in delivered costs between the *Hematite* and *Magnetite Pathways* stem from distinctions in processing routes and intermediate products (as detailed in **Section 3**). In the *Hematite Pathway*, iron ore refers to **direct shipping ore (DSO)**, while in the *Magnetite Pathway*, iron ore refers to **DRI-grade iron ore pellets**. Similarly, in the *Hematite Pathway*, the intermediate iron product refers to **pig iron**. In contrast, in the *Magnetite Pathway*, iron refers to **hot-briquetted iron (HBI)**, each with distinct market values based on their quality and demand.

The higher costs of DRI-grade iron ore pellets produced in the *Magnetite Pathway* reflect the market premium value of high-grade iron ore pellets. Currently, portside prices in China for 65% iron ore pellets are approximately 125 US$ (**180 A$**) per tonne, down from a peak of 150 US$ (**215 A$**) per tonne in January 2024.[39] In comparison, DSO that is produced in the *Hematite Pathway* has a lower market value. Portside prices in China for 62% lump ore, used as a benchmark for DSO, are currently 110 US$ (**160 A$**) per tonne, down from a peak of 150 US$ (**215 A$**) per tonne in January 2024.[40] The intermediate iron product in the *Hematite Pathway,* pig iron, has current portside prices in China of 415 US$ (**595 A$**) per tonne, down from a high of 490 US$ (**700 A$**) per tonne in January 2024.[1] In the *Magnetite Pathway*, the intermediate iron product, HBI, is currently priced at approximately 360 US$ (**515 A$**) per tonne, based on current Indian DRI export prices [2]. For comparison, **medium plate steel** is priced at 530 US$ (**760 A$**) per tonne, down from a peak of 615 US$ (**880 A$**) in January 2024.[41]

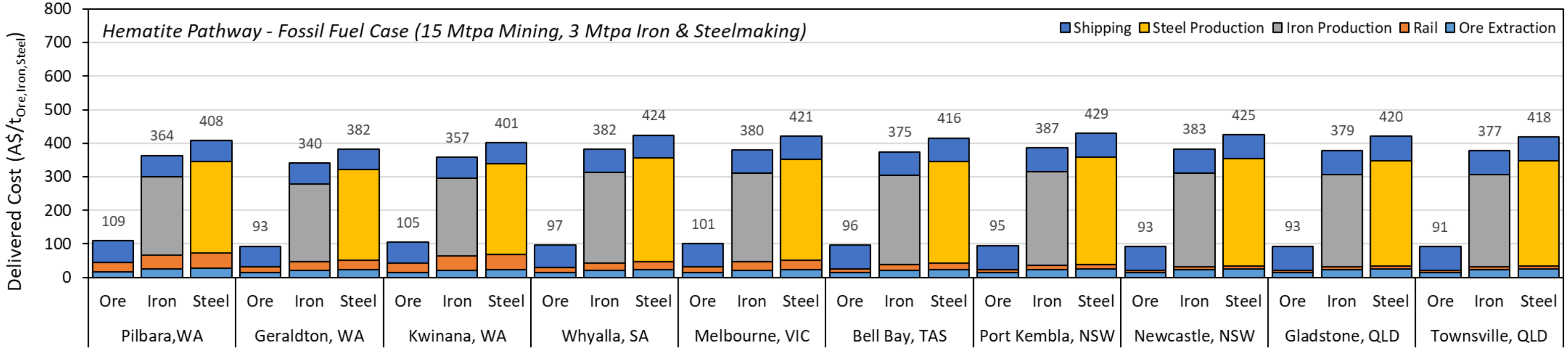
As shown in **Figure 13**, the delivered cost estimates in the *Fossil Fuel Case* are as follows:

- *Hematite Pathway*:
  - Iron ore (DSO) **97–116 A$/tonne**
  - Iron (pig iron) **380–427 A$/tonne**
  - Steel **431–478 A$/tonne**
- *Magnetite Pathway*:
  - Iron ore (DRI-grade pellets) **123–140 A$/tonne**
  - Iron (HBI) **299–349 A$/tonne**
  - Steel **432–486 A$/tonne**

Across the 10 locations analysed, Western Australia (WA) had the lowest delivered costs for iron and steel compared to other regions in Australia, mainly due to lower fossil fuel energy costs compared to the other regions. Among these locations, Geraldton, WA, had the lowest costs for iron and steelmaking in both the *Magnetite* and *Hematite Pathways*. The Pilbara region also showed competitive production costs, ranking 3rd lowest despite higher labour cost estimates than all other locations, benefiting from its relatively low energy costs (**Table 3**, **Section 3.9**).

4.3.1 Impact of Economies of Scale

The estimates provided in **Section 4.3** are based on mine site production capacities of **5 Mtpa** and iron and steel mill capacities of **1 Mtpa facilities**. The following **Figure 17** presents cost analyses for iron and steelmaking facilities operating with a capacity of **3 Mtpa**, and mine site capacity of **15 Mtpa**, where economies of scale can reduce unit production costs.



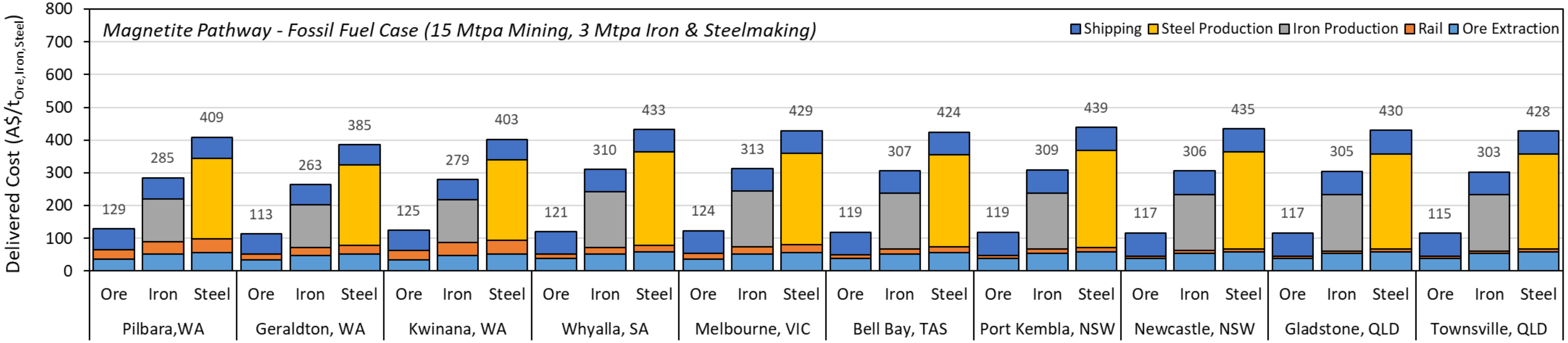


Figure 14. Delivered cost of iron ore, iron and steel from Australia to Germany using current fossil fuel-based technologies (3-fold increase in capacity). Analysis based on a mine site capacity of **15Mtpa** and an iron and steel mill capacity of **3 Mtpa**, with rail and shipping operations assuming maximum deliverable volumes per annum. Iron ore export in the Hematite Pathway refers to the export of Direct Shippable Ore (DSO), whereas iron ore export in the Magnetite Pathway refers to the export of DRI-grade iron ore pellets. Iron export in the Hematite Pathway refers to the export of an iron product similar to pig iron, and iron export in the Magnetite Pathway refers to the export of Hot Briquetted Iron (HBI). Steel in both pathways refers to the export of steel slab. The steelmaking process was assumed to operate as an integrated steel mill, with both ironmaking and steelmaking conducted at the same facility. Values were expressed per tonne of delivered product, adjusted using an Fe content of 60%, 65%, 90% and 98% for DSO, iron ore pellets, iron and steel respectively.

The analysis shows that a 3-fold increase in production capacity (15 Mtpa for mining and 3 Mtpa for iron and steelmaking, compared to 5 Mtpa and 1 Mtpa) can reduce delivered cost estimates to the following:

- *Hematite Pathway*:
    - Iron ore (DSO) **91-109 A$/tonne**
    - Iron (pig iron) **340-387 A$/tonne**
    - Steel **382-429 A$/tonne**
- *Magnetite Pathway*:
    - Iron ore (DRI-grade pellets) **113-129 A$/tonne**
    - Iron (HBI) **263-313 A$/tonne**
    - Steel **385-439 A$/tonne**

This results in a reduction of **5-10%** in delivered costs compared to smaller-scale facilities with iron and steelmaking facilities operating with a capacity of **1 Mtpa**, and mine site capacity of **5 Mtpa**.

Impact of Capital Costs

Each location was assumed to have similar capital costs, despite some locations being more remote, such as the Pilbara, where logistical challenges can drive up costs for construction and delivered equipment. **Figure 15** outlines the impact that higher capital costs, applied to the entire value chain, have over delivered costs.

An **increase in capital costs of 20%** results in an **increase in delivered costs of 2.7%, 5.6% and 6.4%** for iron ore (DSO), iron (pig iron) and steel respectively for the *Hematite Pathway*, and an **increase in delivered costs of 4.1%, 5.3% and 5.8%** for iron ore (DRI-grade pellets), iron (HBI) and steel respectively for the *Magnetite Pathway*.

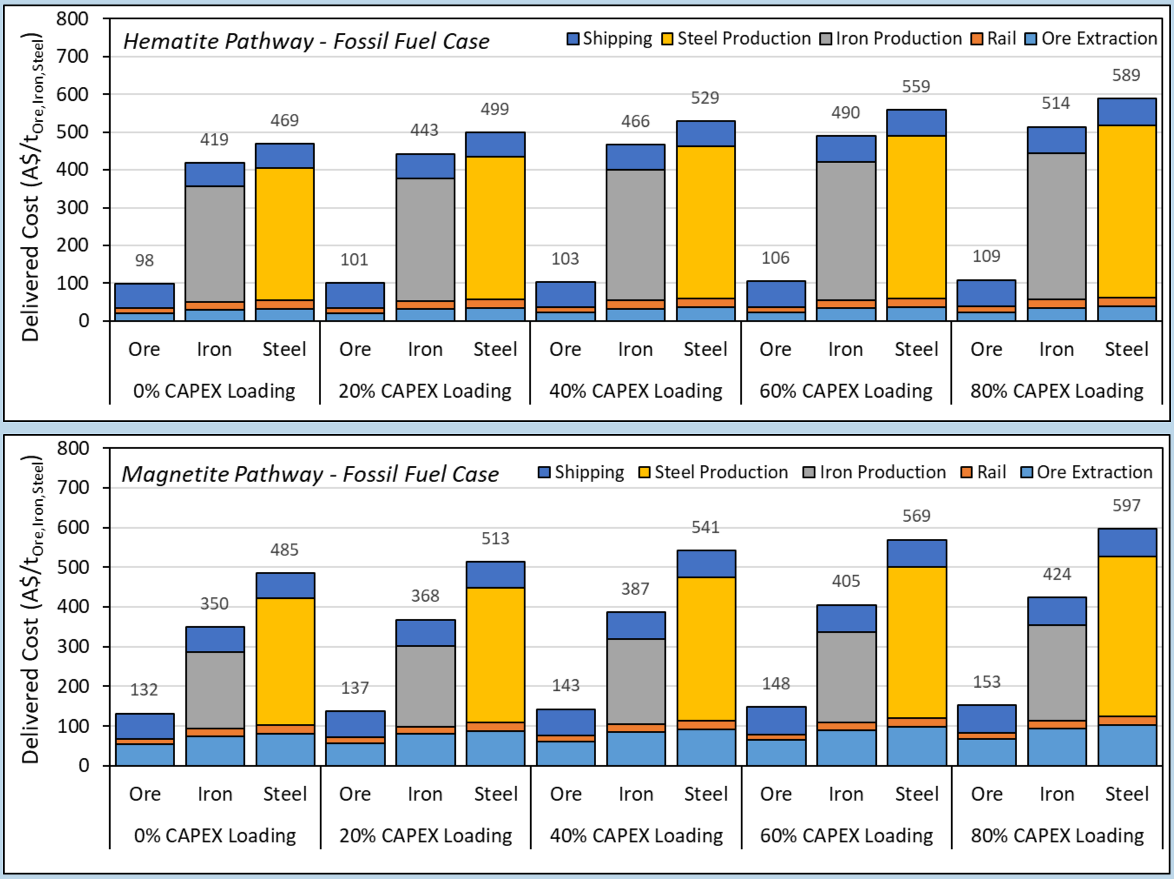


Figure 15. Impact of Capital Costs over delivered cost of iron ore, iron and steel from Australia to Germany using current fossil fuel-based technologies. Analysis based on a mine site capacity of 5Mtpa and an iron and steel mill capacity of 1Mtpa, with rail and shipping operations assuming maximum deliverable volumes per annum. Iron ore export in the Hematite Pathway refers to the export of Direct Shippable Ore (DSO), whereas iron ore export in the Magnetite Pathway refers to the export of DRI-grade iron ore pellets. Iron export in the Hematite Pathway refers to the export of an iron product similar to pig iron, and iron export in the Magnetite Pathway refers to the export of Hot Briquetted Iron (HBI). Steel in both pathways refers to the export of steel slab. The steelmaking process was assumed to operate as an integrated steel mill, with both ironmaking and steelmaking conducted at the same facility. Values were expressed per tonne of delivered product, adjusted using an Fe content of 60%, 65%, 90% and 98% for DSO, iron ore pellets, iron and steel respectively.

5 Developing a Green Iron and Steel Value Chain

Energy (fuel and electricity) plays a much more significant role in overall costs in green iron and steel (compared to the fossil-fuel-based value chain) due to the higher energy costs associated with the use of renewable energy in these processes. Overall, energy costs account for 76% of delivered costs in the Hematite Pathway and 80% in the Magnetite Pathway. Among these, hydrogen gas used in the ironmaking process is the most significant single cost component, representing 51% of total costs in the Hematite Pathway and 48% of total costs in the Magnetite Pathway.

This section examines the costs associated with developing a green iron and steel value chain between Australia and Germany, based on the three export scenarios presented in **Section 2.1**. Each decarbonisation pathway, as outlined in **Section 3**, these assume the integration of renewable electricity, supported by lithium-ion battery energy storage, and green hydrogen produced via alkaline electrolysis. Estimates of the levelised cost of electricity (LCOE) and the levelised cost of hydrogen (LCOH) are provided in **Table 3, Section 3.9.** The optimised system configurations for each region, and other relevant details, are provided in **Appendix 11**.

5.1 Green Hydrogen and Derivatives Production and Export Costs

The first part of this analysis considered the export of renewable energy in four different forms: Liquefied Hydrogen, Liquid Organic Hydrogen Carrier (LOHC), Ammonia and Liquefied Synthetic Natural Gas (SNG). As outlined in **Section 3.6**, for Liquefied Hydrogen, LOHC, and Ammonia, the carrier was converted back to hydrogen for use in hydrogen-based DRI ironmaking. Similarly, for Liquefied SNG, the carrier was regasified to SNG for use in natural gas-based DRI ironmaking. The following **Figure 16** outlines the different cost estimates (expressed as A$/GJ) for producing and exporting renewable energy to the Port of Hamburg, Germany from each of the different Australian production sites identified in **Section 2**.

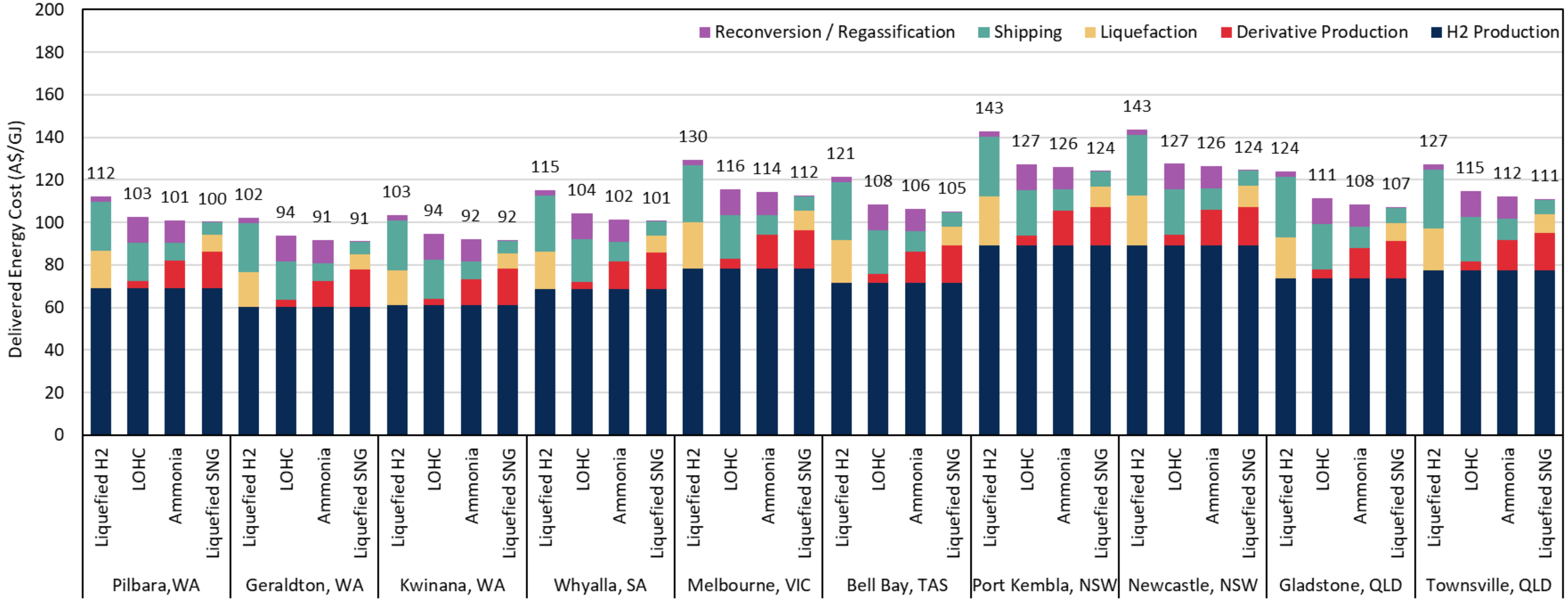


Figure 16. Delivered Energy Cost Estimates for Green Hydrogen and Derivatives export from Australia to Germany. Analysis was performed for Liquefied Hydrogen, Liquid Organic Hydrogen Carrier (LOHC), Ammonia and Liquefied Synthetic Natural Gas (SNG).

Across all locations, the cost of delivered energy ranged from **91–143 A$/GJ**, with Geraldton, Kwinana and the Pilbara in Western Australia showing the lowest production costs. This is primarily due to the high availability of complementary wind and solar resources in these regions, which reduces system costs for hybrid solar PV and wind generation by minimising the need for energy storage (refer to **Appendix 11** for details).

This analysis found slight variation in costs among the derivatives considered. However, liquefied hydrogen emerged as the most expensive option due to the significant costs of liquefaction and higher shipping costs compared to the other derivatives. Overall, the analysis indicates minimal cost differences between using synthetic natural gas or hydrogen (transported as liquefied hydrogen, LOHC, or ammonia) for low-emission ironmaking in Germany. However, it is important to note that while synthetic natural gas offers the advantage of being a "drop-in fuel" compatible with existing infrastructure, its production depends on a sustainable source of CO_2. The availability of low-cost, sustainable sources of CO_2 poses a significant risk to its future viability and application.

Results for hydrogen derivatives used for domestic applications (as described in **Section 3.6**) which includes synthetic natural gas for local iron and steelmaking, and ammonia and methanol as low-carbon maritime fuels, are provided in **Appendix 11**.

Meeting EU Additionality Rules – Impact on H_2 Costs

For exports, both pure hydrogen and hydrogen embedded in products (e.g., green iron and steel) must meet EU RED II/III rules on additionality. Additionality requires renewable electricity from newly built assets, typically via dedicated, directly connected facilities (temporal and geographical correlation) with non-compliance limiting market access (e.g., inability to qualify for RFNBO certification in the EU, exclusion from renewable fuel quotas, and exposure to CBAM or equivalent border taxes).

Herein, as **detailed in Section 3.6,** Australian green hydrogen projects are modelled as islanded (off-grid) systems with dedicated new solar–wind assets directly linked to electrolysers. This inherently meets EU RED II/III requirements (as power is from newly built, directly connected renewables operating in sync with hydrogen output) and avoids the higher compliance costs faced by grid-connected projects. The additional compliance administration costs—such as metering and verification hardware, MRV data management, and third-party certification, however, are not separately itemised in the modelling.

It is estimated that including these increases the H costs by approximately **A$1.5–2.8 per gigajoule, which is less than 1% of the total delivered H_2 cos**t under 2025 assumptions.[3] This modest rise does not significantly impact cost competitiveness while still ensuring compliance with both Australian GO and EU RFNBO certification. In contrast, non-compliance could add A$4–6/GJ (current CBAM at €90/tCO_2-eq) or A$8–10/GJ by 2030 (€140/t), translating to ~A$70–100/t steel (up to ~A$130–160/t), significantly eroding market access and competitiveness.

[3] *MRV cost estimates are based on underlying assumptions drawn from Australian GO/REC frameworks: Metering & verification systems: ~A$50–100k per electrolyser/plant site (capex) plus periodic calibration (~A$5–10k/year) [CER, 2023]; Data management & compliance reporting: ~A$20–40k/year for software, data logging, and staff time [ISCC, 2024]; Third-party audit & certification fees: ~A$30–60k/year depending on audit frequency and scope [ISCC, 2024; CertifHy, 2023]; REC/GO issuance and administration fees: Nominal (<A$0.10/MWh or ~A$1–2k/year for a mid-scale facility) [CER, 2023]. These costs were annualised over 20 years at a 7% real WACC, as per this report's financial assumptions, and divided by annual hydrogen production volumes for each scenario, resulting in total MRV costs of ~A$1.0–1.8 million/year, equivalent to ~A$0.05–0.10/kg$H_2$ or ~A$1.53–2.78/GJ (based on LHV of hydrogen - 120 MJ/kg).*

5.2 Green Iron and Steel Value Chain Costs

Analysis was performed for each of the decarbonisation options outlined in **Table 2**, **Section 3**, considering each aspect of the value chain**.** The specific costs associated with each decarbonisation option are provided in **Appendix 12**. Based on these results, the following decarbonisation options (**Table 4**) were selected to form the basis of the analysis, as these were the decarbonisation options that could be implemented with the lowest cost for each step in the value chain.

Table 4. Lowest-Cost Decarbonisation Pathway Technologies

Stage of Value Chain	Decarbonisation Pathway Technologies
Ore Extraction & Processing	Battery-electric mining vehicles Renewable electricity to provide thermal energy for pelletisation Renewable electricity for ore milling and processing
Rail Transport	Battery electric locomotive
Ironmaking	Direct reduced iron (operating with hydrogen) Renewable electricity for plant operation
Steelmaking	Renewable electricity for plant operation
Shipping	Shipping vessels operating with low-carbon methanol fuel

Figure 17 (below) provides a breakdown of the levelised costs associated with the development of a green iron and steel value chain between Australia and Germany. Values were expressed in cost per tonne of delivered steel. Each aspect of the value chain was modelled independently, showing the levelised cost of production at each step. Furthermore, ironmaking and steelmaking were modelled as standalone processes, showcasing the costs associated with each conversion step if they are operated as independent plants, and includes casting costs for each the ironmaking and steelmaking steps.

Both pathways are estimated to result in the following delivered green steel costs: **A$1,178/tonne$_{Steel}$** for the *Hematite Pathway* and a slightly higher **A$1,239/tonne$_{Steel}$** for the *Magnetite Pathway*. Similar to the fossil-fuel-based value chain (**Section 4.1**), the *Magnetite Pathway* incurs higher iron ore production costs due to the need for **beneficiation and pelletisation** for use in a DRI-EAF process. In contrast, hematite ore is not easily beneficiated (as discussed in **Section 3**), requiring the additional ESF step to remove excess gangue before steelmaking in a BOF. As with the fossil fuel-based value chain, this raises ironmaking costs for the *Hematite Pathway*, which are offset by the lower steelmaking costs of the BOF.

Importantly, energy plays a much more significant role in overall costs (compared to the fossil-fuel-based value chain, **Section 4.1)** due to the higher energy costs associated with the use of renewable energy in these processes. Overall, energy costs (fuel and electricity costs) account for **76%** of delivered costs in the *Hematite Pathway*, and **80%** in the *Magnetite Pathway*. Among these, hydrogen gas used in the ironmaking process is the most significant single cost component, representing **51%** of total costs in the *Hematite Pathway* and **48%** of total costs in the *Magnetite Pathway*.

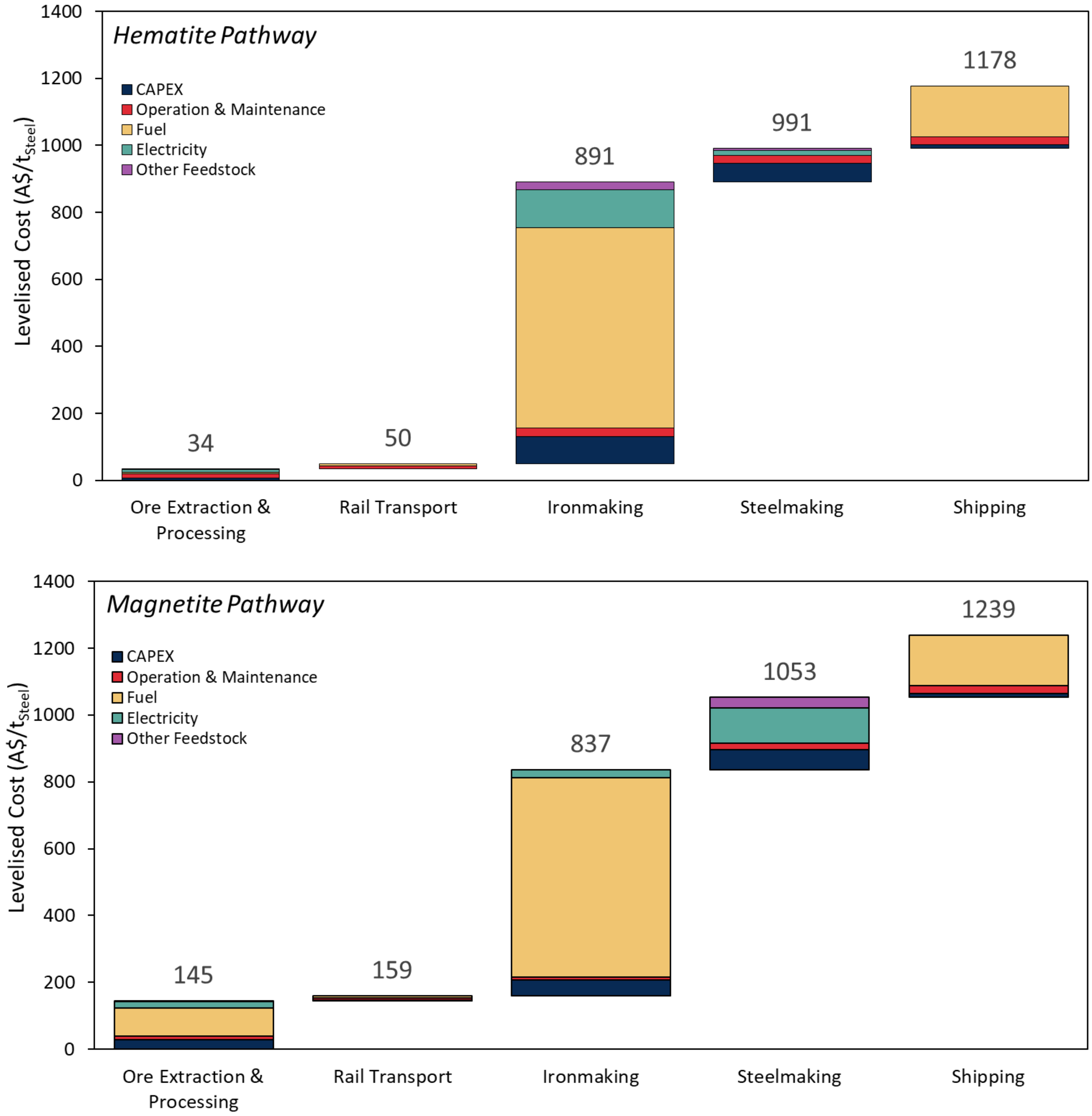


Figure 17. Levelised costs breakdown for a green iron and steel value chain between Australia and Germany. Analysis assumes a mine capacity of 5 Mtpa, an iron and steel mill capacity of 1 Mtpa, and maximum annual deliverable rail and shipping volumes. The Magnetite Pathway uses DRI-grade iron ore pellets and produces Hot Briquetted Iron (HBI). In contrast, the Hematite Pathway uses Direct Shippable Ore (DSO) to make an iron product similar to pig iron. Both pathways produce a steel slab with iron and steelmaking modelled as independent facilities. Plot generated using average-case values for 10 Australian production sites considered (See **Section 3.9** for details). Values were expressed per tonne of delivered steel, adjusted using an Fe content of 60%, 65%, 90% and 98% for DSO, iron ore pellets, iron and steel, respectively.

5.3 Carbon Emissions

As outlined in **Section 4.2**, up to 93% of the emissions of the fossil fuel-based value chain can be mitigated through the decarbonisation options considered in **Table 2**, **Section 3**. Emissions arising from the use of explosives in the mining of iron ore, carbon addition in ESF and EAF processes, and EAF electrode consumption were not addressed in this analysis.

The estimated emissions per tonne of delivered green steel are **77.5 kgCO$_2$-eq/t$_{Steel}$** for the *Hematite Pathway* and **78.3 kgCO$_2$-eq/t$_{Steel}$** for the *Magnetite Pathway*. For the *Hematite*

Pathway, emissions arise from the use of explosives (**1.1 $kgCO_2$-eq/t_{Steel}**), ESF carbon addition (**75.8 $kgCO_2$-eq/t_{Steel}**), BOF carbon addition (**0.4 $kgCO_2$-eq/t_{Steel}**), and shipping (**0.2 $kgCO_2$-eq/t_{Steel}**). Similarly, for the *Magnetite Pathway*, emissions are attributed to the use of explosives (**2.3 $kgCO_2$-eq/t_{Steel}**), EAF carbon addition (**70.5 $kgCO_2$-eq/t_{Steel}**), EAF electrode consumption (**5.2 $kgCO_2$-eq/t_{Steel}**), and shipping (**0.2 $kgCO_2$-eq/t_{Steel}**). Emissions from shipping are attributed to the minimal combustion emissions associated with the use of renewable methanol as a maritime fuel (**Appendix 9**).

Notably, emissions from ESF carbon addition in the *Hematite Pathway* and EAF carbon addition in the *Magnetite Pathway* are slightly lower than the **76.4 $kgCO_2$-eq/t_{Steel}** and **71.1 $kgCO_2$-eq/t_{Steel},** respectively, estimated for the fossil fuel-based pathway (**Figure 12**, **Section 4.2**). This slight reduction is attributed to the lower carbon content of hydrogen-based DRI. Unlike DRI produced from natural gas, which contains some residual carbon, hydrogen-based DRI does not contain carbon. As a result, the model accounts for both CO_2 emissions released and the carbon absorbed during the ESF and EAF process, with hydrogen-based DRI leading to slightly lower net carbon emissions in these processes.

Emissions Threshold for Green Steel

As detailed in **Report 1**, the International Energy Agency (IEA) has set an emissions threshold for near-zero (green) steel production based on the proportion of steel scrap used in steelmaking. This threshold follows a linear scale, ranging from **400 kg CO_2-eq/t_{Steel}** when no steel scrap is used to **50 kg CO_2-eq/t_{Steel}** when steel scrap accounts for 100% of the input. Furthermore, the IEA's definition mandates that green steel production must incorporate a minimum of 30% scrap steel and adhere to the specified constraints of the sliding scale to qualify as near-zero (green) steel.[42,43]

5.4 Location-Specific Cost Estimates

The following sections provide an analysis of the development of a green iron and steel value chain between the locations determined in **Section 2.2**, Australia, for export to the Port of Hamburg, Germany. Notably, these results are indicative, and a more detailed analysis should be conducted for specific locations as needed.

5.4.1 Impact of Decarbonising the Entire Value Chain

The following **Figure 18** provides an overview of the costs associated with the production of iron ore, iron and steel in Australia, where each part of the value chain has been decarbonised (*Green Case*), using the decarbonisation options outlined in **Table 4**. Costs are expressed per tonne of the delivered product—iron ore per tonne of iron ore, iron per tonne of iron, and steel per tonne of steel delivered iron ore, iron exports per tonne of delivered iron, and steel exports per tonne of delivered steel.

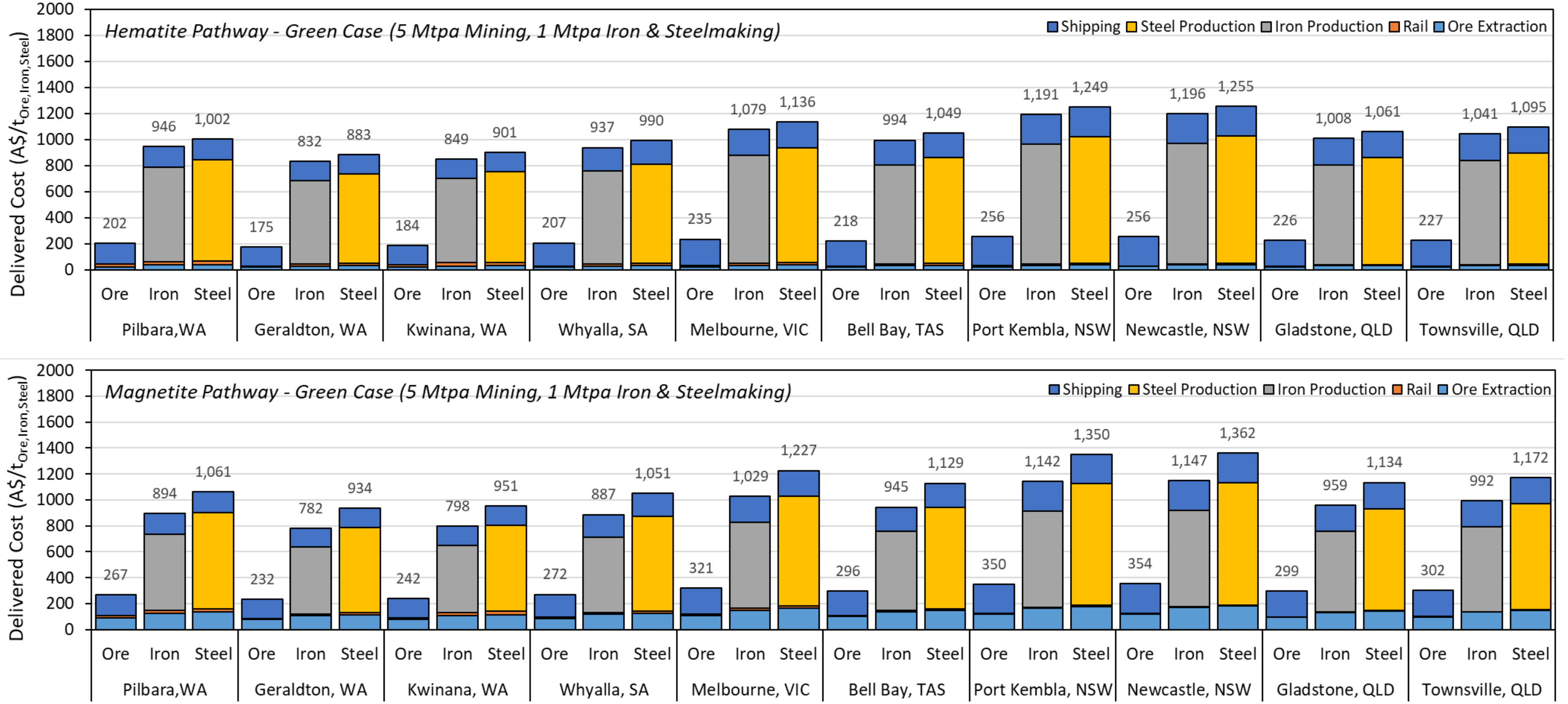


Figure 18. Delivered cost of iron ore, iron and steel from Australia to Germany using green technologies. Analysis based on a mine site capacity of **5Mtpa** and an iron and steel mill capacity of **1Mtpa**, with rail and shipping operations assuming maximum deliverable volumes per annum. Iron ore export in the Hematite Pathway refers to the export of Direct Shippable Ore (DSO). In contrast, iron ore export in the Magnetite Pathway refers to the export of DRI-grade iron ore pellets. Iron export in the Hematite Pathway refers to the export of an iron product similar to pig iron, and iron export in the Magnetite Pathway refers to the export of Hot Briquetted Iron (HBI). Steel in both pathways refers to the export of steel slab. The steelmaking process was assumed to operate as an integrated steel mill, with both ironmaking and steelmaking conducted at the same facility. Values were expressed per tonne of delivered product, adjusted using an Fe content of 60%, 65%, 90% and 98% for DSO, iron ore pellets, iron and steel, respectively.

As outlined in **Section 4.3**, variations in delivered costs between the *Hematite* and *Magnetite Pathways* arise from differences in processing methods and intermediate products. In the *Hematite Pathway*, iron ore refers to **direct shipping ore (DSO),** whereas in the *Magnetite Pathway*, iron ore refers to **DRI-grade iron ore pellets**. Likewise, the intermediate iron product differs between pathways—**pig iron** in the *Hematite Pathway* and hot-briquetted iron (HBI) in the *Magnetite Pathway*.

As shown in **Figure 18,** the delivered cost estimates in the *Green Case* are as follows. These values are then compared to cost estimates from the *Fossil Fuel Case,* as determined in **Figure 13**, **Section 4.3**.

- *Hematite Pathway*:
  - Iron ore (DSO) **177–259 A$/tonne**
    - 85–125% premium compared to *Fossil Fuel Case* (**97–116 A$/tonne**)
    - 10–60% premium compared to current portside prices (**160 A$/tonne**)[40]
  - Iron (pig iron) **834–1,198 A$/tonne**
    - 120–180% premium compared to *Fossil Fuel Case* (**380–427 A$/tonne**)
    - 40–100% premium compared to current portside prices (**595 A$/tonne**)[1]
  - Steel **885–1,257 A$/tonne**
    - 105–165% premium compared to *Fossil Fuel Case* (**431–478 A$/tonne**)
    - 15–65% premium compared to current portside prices (**760 A$/tonne**)[41]
- *Magnetite Pathway*:
  - Iron ore (DRI-grade pellets) **234–356 A$/tonne**
    - 90–155% premium compared to *Fossil Fuel Case* (**123–140 A$/tonne**)
    - 30–100% premium compared to current portside prices (**180 A$/tonne**)[39]
  - Iron (HBI) **784–1,150 A$/tonne**
    - 165–230% premium compared to *Fossil Fuel Case* (**299–349 A$/tonne**)
    - 50–120% premium compared to current portside prices (**515 A$/tonne**)[2]
  - Steel **936–1,364 A$/tonne**
    - 115–180% premium compared to *Fossil Fuel Case* (**432–486 A$/tonne**)
    - 25–80% premium compared to current portside prices (**760 A$/tonne**)[41]

The *Green Case* results in a premium ranging from **85-230%** compared to the *Fossil Fuel Case*, and **10-120%** for portside prices of DSO, DRI-grade pellets, pig iron, and medium-plate steel.

These cost estimates account for the entire value chain. However, when considering only the production cost of green HBI (iron produced via the *Magnetite Pathway*), estimates range from **516–745 A$/tonne** (see **Appendix 12.2** for details). These figures align with a recent report conducted by the Minerals Research Institute of Western Australia (MRIWA), which estimates the cost of green HBI from magnetite ore at **712 A$/tonne**.[15] Similarly, for steel produced from green HBI (steel produced via the *Magnetite Pathway*), estimates range from **658-944 A$/tonne** (see **Appendix 12.3**), which also align with MRIWA estimates of **908 A$/tonne**.[15]

Moreover, recent analysis by Deloitte and WWF Australia estimates the cost of green steel produced via the Hydrogen-DRI-EAF pathway (referred to herein as the *Magnetite Pathway*) at approximately **1,230 A$/tonne**.[44] This estimate assumes that HBI is produced in Australia and then shipped to steelmaking nations in the Asia-Pacific region (China, Japan, and Korea) for conversion into steel in an EAF. This aligns with our estimated range of **934–1,362 A$/tonne**, although our modelling focuses on the costs of integrated steelmaking in Australia for export to Germany. However, their analysis projects significantly higher production costs for green steel in the Pilbara region, estimating **1,730 A$/tonne**, though no clear justification is provided for these higher cost estimates.

For both the *Fossil Fuel Case* and *Green Case*, Geraldton, WA, had the lowest production and export costs for iron and steel (**Figure 13** and **Figure 18**). This cost advantage is primarily due to the low fossil fuel energy costs and strong renewable energy potential of the region, showing reasonable collocation of solar and wind resources, minimising energy storage costs, resulting in lower projected renewable energy costs compared to the other areas analysed. Similarly, the Pilbara region exhibited low production cost estimates, ranking 3rd cheapest in the *Fossil Fuel Case* (**Figure 13, Section 4.3**) and 4th cheapest in the *Green Case* (**Figure 18, Section 5.4**) owing to the low energy costs and renewable energy generation potential for that region, despite having higher labour cost estimates compared to all other regions analysed (**Table 3**, **Section 3.9**). However, despite ranking behind some of the other locations analysed, it is worth noting that the Pilbara region benefits from having some of the world's largest operating iron ore mines, extensive port infrastructure, vast areas of uninhabited land suitable for renewable energy generation, and proximity to Southeast Asian markets. These factors present synergies that could support the development of a green iron and steel export industry in the region, which were not directly accounted for in this analysis.

5.4.2 Impact of Economies of Scale

Estimates provided in **Section 5.4.1** are based on mine site production capacities of **5 Mtpa** and iron and steel mill capacities of **1 Mtpa facilities**. The following **Figure 19** presents cost analyses for green iron and steelmaking facilities operating with a capacity of **3 Mtpa**, and mine site capacity of **15 Mtpa**, where economies of scale can reduce unit production costs.

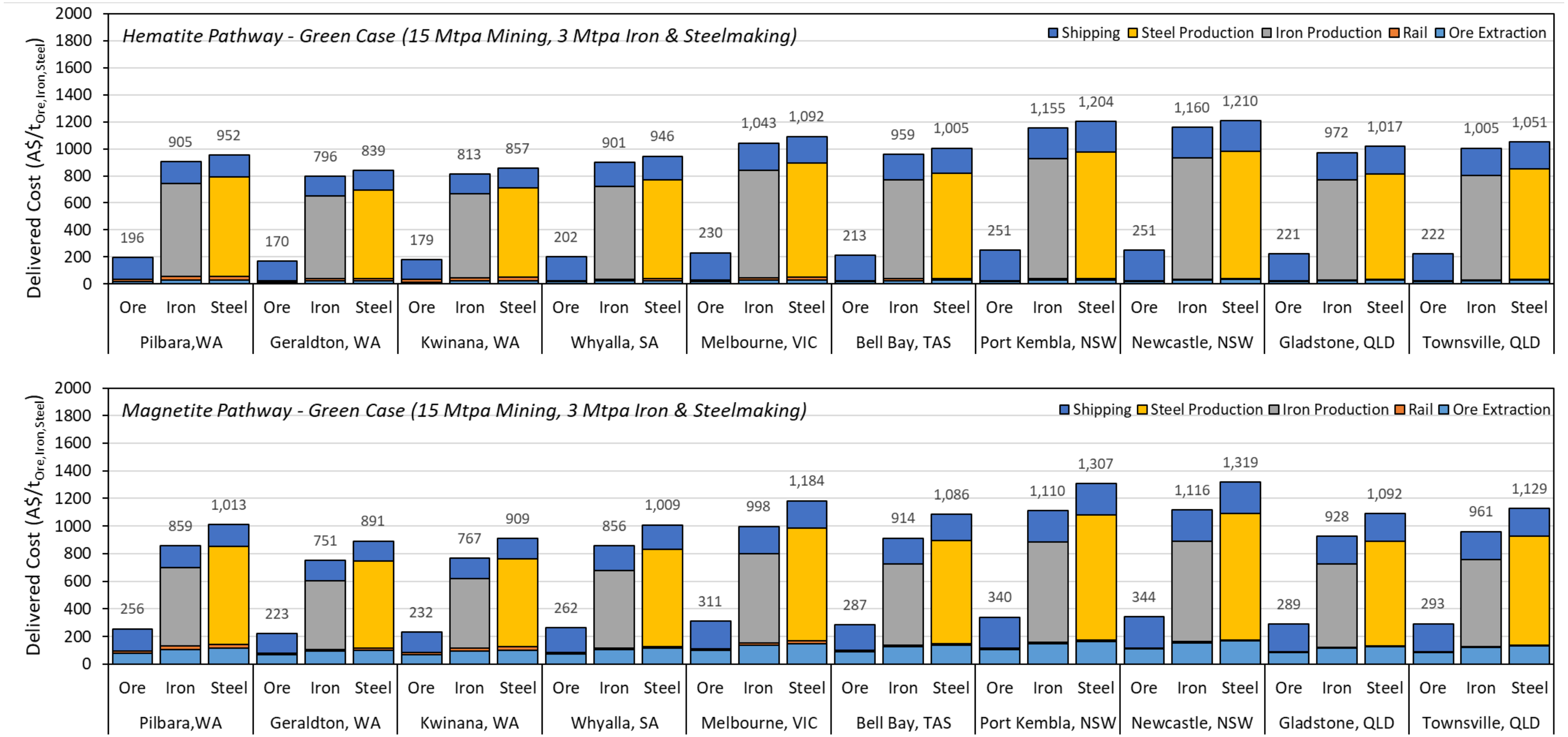


Figure 19. Delivered cost of iron ore, iron and steel from Australia to Germany using green technologies (3-fold increase in capacity). Analysis based on a mine site capacity of **15Mtpa** and an iron and steel mill capacity of **3Mtpa**, with rail and shipping operations assuming maximum deliverable volumes per annum. Iron ore export in the Hematite Pathway refers to the export of Direct Shippable Ore (DSO), whereas iron ore export in the Magnetite Pathway refers to the export of DRI-grade iron ore pellets. Iron export in the Hematite Pathway refers to the export of an iron product similar to pig iron, and iron export in the Magnetite Pathway refers to the export of Hot Briquetted Iron (HBI). Steel in both pathways refers to the export of steel slab. The steelmaking process was assumed to operate as an integrated steel mill, with both ironmaking and steelmaking conducted at the same facility. Values were expressed per tonne of delivered product, adjusted using an Fe content of 60%, 65%, 90% and 98% for DSO, iron ore pellets, iron and steel respectively.

As shown in **Figure 19** delivered cost estimates in the *Green Case* for larger capacity facilities are as follows. These values are then compared to cost estimates from the *Fossil Fuel Case* of an equivalent capacity, as determined in **Figure 14**, **Section 4.3.1**.

- *Hematite Pathway*:
    - Iron ore (DSO) **170–251 A$/tonne**
        - 85–130% premium compared to *Fossil Fuel Case* (**91-109 A$/tonne**)
        - 5–55% premium compared to current portside prices (**160 A$/tonne**)[40]
    - Iron (pig iron) **796–1,160 A$/tonne**
        - 135–200% premium compared to *Fossil Fuel Case* (**340-387 A$/tonne**)
        - 35–95% premium compared to current portside prices (**595 A$/tonne**)[1]
    - Steel **839–1,210 A$/tonne**
        - 120–180% premium compared to *Fossil Fuel Case* (**382–429 A$/tonne**)
        - 10–60% premium compared to current portside prices (**760 A$/tonne**)[41]
- *Magnetite Pathway*:
    - Iron ore (DRI-grade pellets) **223–344 A$/tonne**
        - 100–165% premium compared to *Fossil Fuel Case* (**113–129 A$/tonne**)
        - 25–90% premium compared to current portside prices (**180 A$/tonne**)[39]
    - Iron (HBI) **751–1,116 A$/tonne**
        - 185–255% premium compared to *Fossil Fuel Case* (**263–313 A$/tonne**)
        - 45–115% premium compared to current portside prices (**515 A$/tonne**)[2]
    - Steel **891–1,319 A$/tonne**
        - 130–200% premium compared to *Fossil Fuel Case* (**385–439 A$/tonne**)
        - 15–75% premium compared to current portside prices (**760 A$/tonne**)[41]

The *Green Case* for larger capacity facilities results in a premium ranging from **85-255%** compared to the *Fossil Fuel Case*, and **5-115%** for portside prices of DSO, DRI-grade pellets, pig iron, and medium-plate steel.

5.4.3 Impact of Decarbonising Iron and Steelmaking Only

Estimates provided in **Sections 5.4.1** and **5.4.2** reflect the costs of developing a fully decarbonised green iron and steel value chain (where each aspect of the value chain is decarbonised). However, the transition to a green iron and steel industry is expected to follow a phased approach, prioritising the decarbonisation of the most carbon-intensive, technically and economically viable stages first. At the same time, other processes continue to rely on conventional technologies in the near term. In this context, the following analysis considers the cost of **exporting green iron and green steel while maintaining fossil fuel-based operations for ore extraction, rail transport, and shipping**. This approach reflects the practical challenges of decarbonising the entire supply chain in the short term. It acknowledges the need for a gradual shift as low-carbon alternatives become more commercially feasible.

Figure 20 presents cost estimates for iron and steelmaking facilities with a production capacity of **1 Mtpa** and a corresponding mine site capacity of **5 Mtpa,** where **only the iron and steelmaking steps have been decarbonised**.

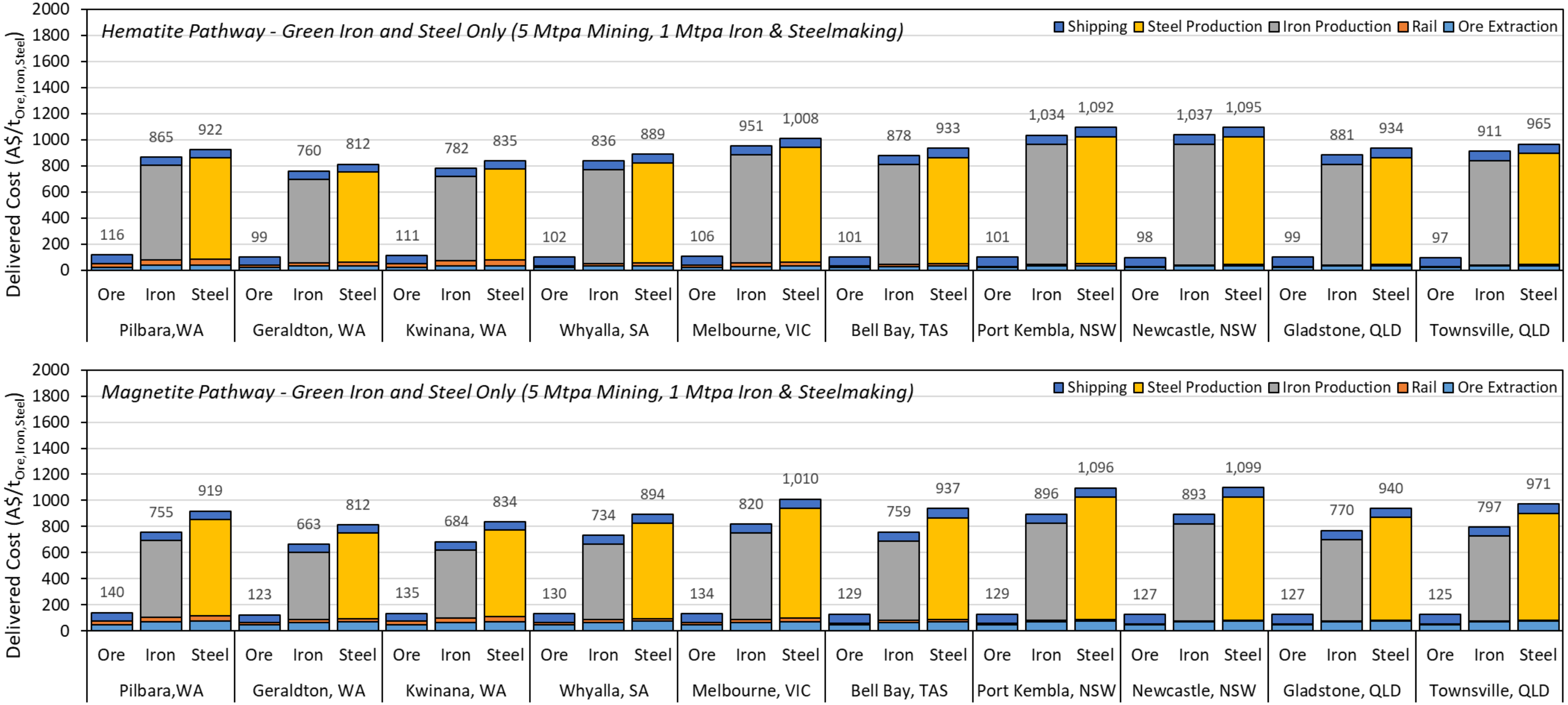


Figure 20. Delivered cost of iron ore, iron and steel from Australia to Germany considering green iron and steel only in a fossil fuel-based value chain. Analysis based on a mine site capacity of **5Mtpa** and an iron and steel mill capacity of **1Mtpa**, with rail and shipping operations assuming maximum deliverable volumes per annum. Iron ore export in the Hematite Pathway refers to the export of Direct Shippable Ore (DSO), whereas iron ore export in the Magnetite Pathway refers to the export of DRI-grade iron ore pellets. Iron export in the Hematite Pathway refers to the export of an iron product similar to pig iron, and iron export in the Magnetite Pathway refers to the export of Hot Briquetted Iron (HBI). Steel in both pathways refers to the export of steel slab. The steelmaking process was assumed to operate as an integrated steel mill, with both ironmaking and steelmaking conducted at the same facility. Values were expressed per tonne of delivered product, adjusted using an Fe content of 60%, 65%, 90% and 98% for DSO, iron ore pellets, iron and steel respectively.

Decarbonising only the iron and steel production stages results in the following delivered costs and corresponding premiums compared to both the fossil fuel-based value chain (*Fossil-Fuel Case*, **Figure 13, Section 4.3**) and current portside prices.

- *Hematite Pathway*:
  - Iron (pig iron) **760–1,037 A$/tonne**
    - 100–140% premium compared to *Fossil Fuel Case* (**380–427 A$/tonne**)
    - 30–75% premium compared to current portside prices (**595 A$/tonne**)[1]
  - Steel **812–1,095 A$/tonne**
    - 90–130% premium compared to *Fossil Fuel Case* (**431–478 A$/tonne**)
    - 5–45% premium compared to current portside prices (**760 A$/tonne**)[41]
- *Magnetite Pathway*:
  - Iron (HBI) **663–896 A$/tonne**
    - 120–155% premium compared to *Fossil Fuel Case* (**299–349 A$/tonne**)
    - 30–75% premium compared to current portside prices (**515 A$/tonne**)[2]
  - Steel **812–1,099 A$/tonne**
    - 90–125% premium compared to *Fossil Fuel Case* (**432–486 A$/tonne**)
    - 5–45% premium compared to current portside prices (**760 A$/tonne**)[41]

Decarbonising only the iron and steelmaking stages reduces premiums to **90-155%** compared to the *Fossil Fuel Case*, down from **85-230%,** and **5–75%** compared to current portside prices, down from **10–120%** when the entire value chain is decarbonised (**Section 5.4.1**).

5.4.4 Impact of the A\$2/kg$_{H2}$ Tax Credit

Australia currently offers an **A\$2/kg$_{H2}$ tax credit** for eligible hydrogen production, which is designed to incentivise and support the growth of the hydrogen sector by offsetting production costs and enhancing the cost-competitiveness of low-carbon hydrogen. The incentive will be available between 1 July 2027 and 30 June 2040 for a maximum of 10 years for projects that reach production or take a final investment decision prior to 30 June 2030.[45]

The following **Figure 21** presents cost estimates for iron and steelmaking facilities with a production capacity of **1 Mtpa** and a corresponding mine site capacity of **5 Mtpa,** where **only the iron and steelmaking steps have been decarbonised** and **hydrogen production costs have been offset using an A\$2/kg$_{H2}$ tax credit**.

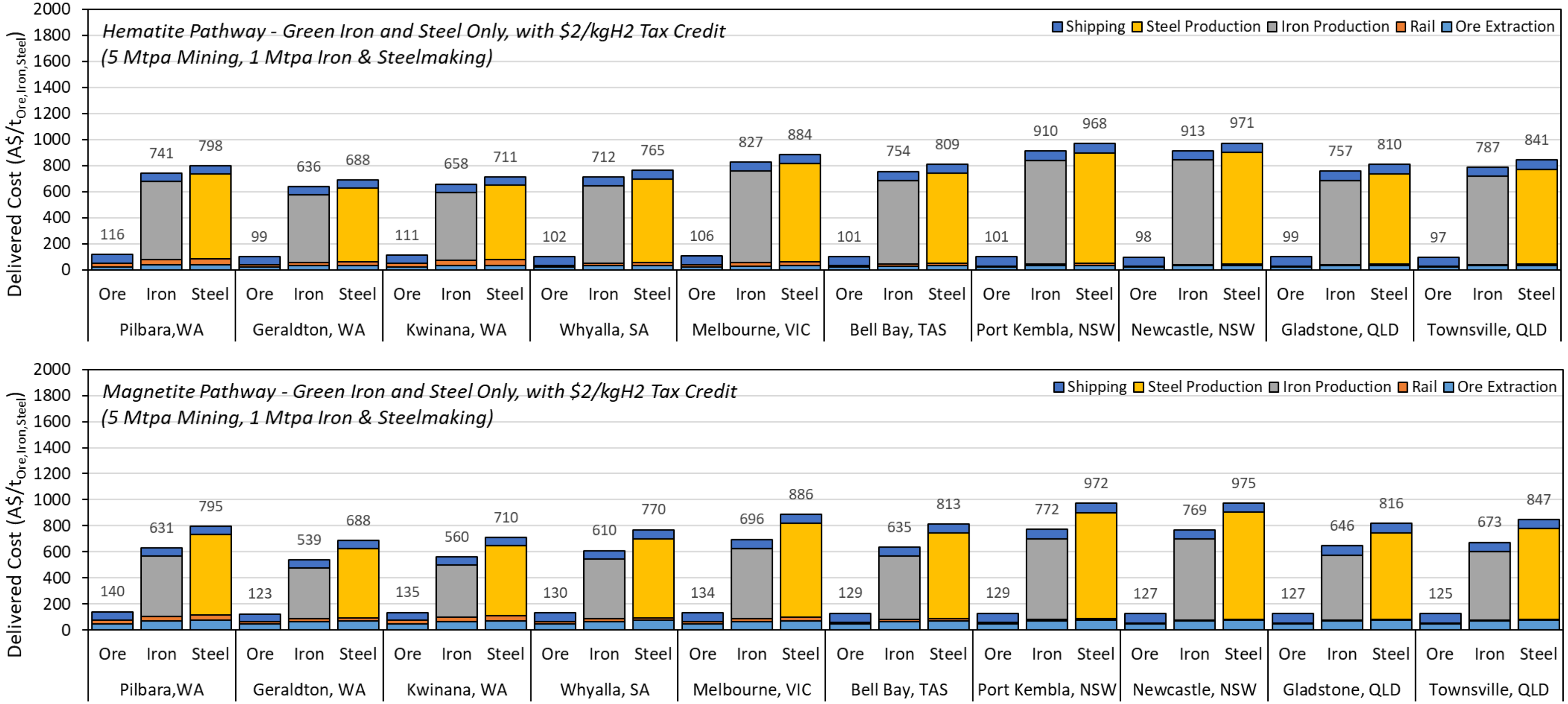


Figure 21. Delivered cost of iron ore, iron and steel from Australia to Germany considering green iron and steel only in a fossil fuel-based value chain including a A\$2/kg$_{H2}$ tax credit. Analysis based on a mine site capacity of **5Mtpa** and an iron and steel mill capacity of **1Mtpa**, with rail and shipping operations assuming maximum deliverable volumes per annum. Iron ore export in the Hematite Pathway refers to the export of Direct Shippable Ore (DSO), whereas iron ore export in the Magnetite Pathway refers to the export of DRI-grade iron ore pellets. Iron export in the Hematite Pathway refers to the export of an iron product similar to pig iron, and iron export in the Magnetite Pathway refers to the export of Hot Briquetted Iron (HBI). Steel in both pathways refers to the export of steel slab. The steelmaking process was assumed to operate as an integrated steel mill, with both ironmaking and steelmaking conducted at the same facility. Values were expressed per tonne of delivered product, adjusted using an Fe content of 60%, 65%, 90% and 98% for DSO, iron ore pellets, iron and steel respectively.

Applying the **A$2/kg$_{H2}$ tax credit** and **decarbonising only the iron and steel production stages** results in the following delivered costs and corresponding premiums compared to both the fossil fuel-based value chain (*Fossil-Fuel Case*, **Figure 13, Section 4.3**) and current portside prices.

- *Hematite Pathway*:
  - Iron (pig iron) **636–913 A$/tonne**
    - 65–115% premium compared to *Fossil Fuel Case* (**380–427 A$/tonne**)
    - 5–55% premium compared to current portside prices (**595 A$/tonne**)[1]
  - Steel **688–971 A$/tonne**
    - 60–100% premium compared to *Fossil Fuel Case* (**431–478 A$/tonne**)
    - 0–30% premium compared to current portside prices (**760 A$/tonne**)[41]
- *Magnetite Pathway*:
  - Iron (HBI) **539–772 A$/tonne**
    - 80–120% premium compared to *Fossil Fuel Case* (**299–349 A$/tonne**)
    - 5–50% premium compared to current portside prices (**515 A$/tonne**)[2]
  - Steel **688–975 A$/tonne**
    - 60–100% premium compared to *Fossil Fuel Case* (**432–486 A$/tonne**)
    - 0–30% premium compared to current portside prices (**760 A$/tonne**)[41]

This results in a premium ranging from **0-55%** compared to current portside prices. Meaning that **under this scenario, green iron and green steel can be produced at or below current market rates** (as seen with green steel) **or close to current market rates** (as seen with green iron).

6 Prospects for Australia and Germany

Meeting 10% of Germany's steel demand through iron ore and renewable energy exports would require approximately 5.34–5.78 Mt of iron ore, 26.3 PJ (0.219 Mt) of hydrogen gas, and 6.67–7.20 PJ (1.84-1.99 TWh) of local energy generation. Conversely, meeting this same demand through green iron exports is far less energy intensive, requiring 3.85 Mt of green iron and 0.655–6.04 PJ (0.181-1.67 TWh) of local energy generation.

In 2023, Germany ranked as the 7th largest steel-producing nation, with a total crude steel production of **35.4 Mt**, pig iron production of **23.6 Mt**, and an estimated direct reduced iron (DRI) production of **0.2 Mt**.[46] To meet this demand, Germany imported **37.5 Mt of iron ore**.[46] In 2022, Australia produced a total of **944.1 Mt of iron ore** [46]. In 2021, Australian pig iron and crude steel production were **3.75** and **5.78 Mt**, respectively.[47]

6.1 Feedstock Requirements for Developing a Green Iron and Steel Value Chain

An overview of the energy requirements for ironmaking and steelmaking has been provided in **Table 5**. All values have been expressed per tonne of **hot metal (HM)**, and do not account for energy requirements for rolling or casting of iron or steel products.

Table 5. Energy Requirements for Ironmaking and Steelmaking

Natural Gas-based Iron and Steelmaking			
Hematite Pathway		Natural Gas ($GJ/tonne_{HM}$)	Electricity ($GJ/tonne_{HM}$, $kWh/tonne_{HM}$)
Ironmaking	DRI Shaft Furnace	10.0	0.252 (70.0 kWh)
	Oxygen PSA[1]		0.004 (1.20 kWh)
	Electric Smelting Furnace		1.37 (380 kWh)
	Total	**10.0**	**1.62 (451 kWh)**
Steelmaking	Basic Oxygen Furnace		0.076 (21.0 kWh)
	Oxygen PSA[1]		0.109 (30.4 kWh)
	Total		**0.185 (51.4 kWh)**
Magnetite Pathway		Natural Gas ($GJ/tonne_{HM}$)	Electricity ($GJ/tonne_{HM}$, $kWh/tonne_{HM}$)
Ironmaking	DRI Shaft Furnace	10.0	0.252 (70.0 kWh)
	Oxygen PSA[1]		0.004 (1.20 kWh)
	Total	**10.0**	**0.256 (71.2 kWh)**
Steelmaking	Electric Arc Furnace[2]		1.63 (453 kWh)
	Oxygen PSA[1]		0.075 (20.8 kWh)
	Total		**1.71 (474 kWh)**
Hydrogen Gas-based Iron and Steelmaking			
Hematite Pathway		Hydrogen Gas ($GJ/tonne_{HM}$)	Electricity ($GJ/tonne_{HM}$, $kWh/tonne_{HM}$)
Ironmaking	DRI Shaft Furnace	7.43	0.252 (70.0 kWh)
	Oxygen PSA[1]		0.076 (21.2 kWh)
	Electric Smelting Furnace		1.37 (380 kWh)
	Total	**7.43**	**1.70 (471 kWh)**
Steelmaking	Basic Oxygen Furnace		0.076 (21.0 kWh)
	Oxygen PSA[1]		0.109 (30.4 kWh)
	Total		**0.185 (51.4 kWh)**
Magnetite Pathway		Hydrogen Gas ($GJ/tonne_{HM}$)	Electricity ($GJ/tonne_{HM}$, $kWh/tonne_{HM}$)
Ironmaking	DRI Shaft Furnace	7.43	0.252 (70.0 kWh)
	Oxygen PSA[1]		0.076 (21.2 kWh)
	Total	**7.43**	**0.328 (91.2 kWh)**
Steelmaking	Electric Arc Furnace[2]		1.63 (453 kWh)
	Oxygen PSA[1]		0.075 (20.8 kWh)
	Total		**1.71 (474 kWh)**

1. Oxygen PSA refer to Oxygen Pressure Swing Adsorption, which was the method for generating oxygen assumed by this analysis
2. Electric arc furnace energy demand assumed to be that of a unit that is not hot-linked (refer to **Appendix 7** for details).

Although these estimates suggest that hydrogen-based DRI processes require less energy than those using natural gas, this comparison is based on theoretical calculations for hydrogen consumption. In contrast, the natural gas estimates reflect data from current operating plants (see **Appendix 4** for details). Consequently, while the hydrogen pathway may appear less energy-intensive than the natural gas pathway, real-world data from hydrogen-based DRI operations are needed to validate these assumptions.

Considering the three key export scenarios outlined in **Report 1**, which detail Australia's potential contributions to Germany's green iron and steel industry, the following feedstock requirements were estimated to meet this demand (**Table 6**). Values were based on the use of **hydrogen gas as a reducing agent** in a hydrogen gas-based ironmaking process.

Table 6. Feedstock Requirements for the Export of Iron Ore, Iron, Steel and Renewable Energy to Facilitate the Production of Green Iron and Steel in Germany

Scenario 1: Export iron ore and renewable energy to facilitate the production of green iron and steel in Germany			
Hematite Pathway	Iron Ore (Mt)[1]	Hydrogen Gas (PJ, Mt)	Domestic Electricity Requirements (PJ, TWh)[2]
1% Demand (~0.354 Mt)	0.578	2.63 (0.022 Mt)	0.667 (0.184 TWh)
10% Demand (~3.54 Mt)	5.78	26.3 (0.219 Mt)	6.67 (1.84 TWh)
25% Demand (~8.85 Mt)	14.5	65.8 (0.548 Mt)	16.7 (4.61 TWh)
50% Demand (~17.7 Mt)	28.9	132 (1.10 Mt)	33.3 (9.22 TWh)
100% Demand (~35.4 Mt)	57.8	263 (2.19 Mt)	66.7 (18.4 TWh)
Magnetite Pathway	Iron Ore (Mt)[1]	Hydrogen Gas (PJ, Mt)	Domestic Electricity Requirements (PJ, TWh)[2]
1% Demand (~0.354 Mt)	0.534	2.63 (0.022 Mt)	0.720 (0.199 TWh)
10% Demand (~3.54 Mt)	5.34	26.3 (0.219 Mt)	7.20 (1.99 TWh)
25% Demand (~8.85 Mt)	13.3	65.8 (0.548 Mt)	18.0 (4.99 TWh)
50% Demand (~17.7 Mt)	26.7	132 (1.10 Mt)	36.0 (10.0 TWh)
100% Demand (~35.4 Mt)	53.4	263 (2.19 Mt)	72.0 (19.9 TWh)
Scenario 2: Export green iron and renewable energy to facilitate the production of green steel in Germany			
Hematite Pathway		Iron (Mt)[3]	Domestic Electricity Requirements (PJ, TWh)[2]
1% Demand (~0.354 Mt)		0.385	0.066 (0.018 TWh)
10% Demand (~3.54 Mt)		3.85	0.655 (0.181 TWh)
25% Demand (~8.85 Mt)		9.64	1.64 (0.454 TWh)
50% Demand (~17.7 Mt)		19.3	3.28 (0.907 TWh)
100% Demand (~35.4 Mt)		38.5	6.55 (1.81 TWh)
Magnetite Pathway		Iron (Mt)[3]	Domestic Electricity Requirements (PJ, TWh)[2]
1% Demand (~0.354 Mt)		0.385	0.604 (0.167 TWh)
10% Demand (~3.54 Mt)		3.85	6.04 (1.67 TWh)
25% Demand (~8.85 Mt)		9.64	15.1 (4.18 TWh)
50% Demand (~17.7 Mt)		19.3	30.2 (8.36 TWh)
100% Demand (~35.4 Mt)		38.5	60.4 (16.7 TWh)
Scenario 3: Export green steel to Germany for conversion to specialty steels and products in Germany			
Hematite Pathway			Steel (Mt)[4]
1% Demand (~0.354 Mt)			0.354
10% Demand (~3.54 Mt)			3.54
25% Demand (~8.85 Mt)			8.85
50% Demand (~17.7 Mt)			17.7
100% Demand (~35.4 Mt)			35.4
Magnetite Pathway			Steel (Mt)[4]
1% Demand (~0.354 Mt)			0.354
10% Demand (~3.54 Mt)			3.54
25% Demand (~8.85 Mt)			8.85
50% Demand (~17.7 Mt)			17.7
100% Demand (~35.4 Mt)			35.4

1. Iron ore estimates for the *Hematite Pathway* assume direct shippable ore (DSO) with a grade of 60%. Estimates for the *Magnetite Pathway* assume DRI-grade iron ore pellets with an iron content of 65%. For a final steel content of 98% metallic iron.
2. Electricity requirements are expressed as domestic electricity requirements, representing the energy needed at the point of production; however, this energy demand can be met through the import of renewable energy in the form of hydrogen or its derivatives (ensuring to account for electrical energy conversion efficiency).
3. Iron estimates for both the *Hematite Pathway* and *Magnetite Pathway* assume an iron product with a metallic iron content of 90%, for a final steel content of 98% metallic iron.
4. The conversion of steel to specialty steels would require addition energy inputs which have not been accounted for in this analysis

As outlined in **Report 1**, many German steelmakers are transitioning to low-carbon steelmaking by adopting DRI processes coupled with electric arc furnaces (EAF). These DRI-EAF processes require the use of high-grade ore, such as is achievable from beneficiated magnetite ore (as described in **Section 3.4**). Despite Australia's significant iron ore exports, currently only a small proportion (less than 4%) pertains to the exports of beneficiated magnetite ores.[7] In 2018, Australia had three main magnetite-producing projects: Sino Iron in the Pilbara (**19 Mt** of wet magnetite concentrate), Karara in the mid-west (**7.8 Mt** dry magnetite concentrate), and Savage River in Tasmania (**2.37 Mt** of magnetite pellets).[7] Although beneficiated magnetite ore represents a small proportion of Australia's total iron ore exports, these volumes, totalling **29.17 Mt**, could theoretically meet 50% of Germany's steel demand through this pathway. However, much of this production would already be committed to existing off-takers, limiting its immediate availability for new supply chains.

Across all three export scenarios, electricity requirements are expressed as domestic electricity demand, representing the energy needed at the point of production. However, similar to the requirements for hydrogen as a reducing agent in ironmaking, the import of renewable hydrogen and its derivatives can also be used to meet this electricity demand, ensuring that conversion efficiency is accounted for when producing the electricity from these fuels.

Export **Scenario 1** (which considered the export of raw materials and renewable energy to facilitate green iron and steel production in Germany) requires the largest export of energy, mostly in the form of hydrogen gas as a reducing agent for ironmaking, with minimal differences in the total energy requirements between the *Hematite* and *Magnetite Pathways*.

However, when considering **Scenario 2** (which considered the export of green iron and renewable energy to facilitate green steel production in Germany), there is a notable difference between the energy requirements for renewable energy export for the *Hematite* and *Magnetite Pathways*, this is owing to the relatively small amount of electrical energy required for steelmaking in a basic oxygen furnace (BOF) for the *Hematite Pathway* compared to the that of an electric arc furnace (EAF), as is used for the *Magnetite Pathway* (shown in **Table 5**).

Lastly, although **Scenario 3** (which considers the export of green steel) does not include an energy requirement for green steel production, imported steel used in Germany would still require energy for converting crude steel into specialty steel products. However, this additional energy demand is not accounted for in this analysis.

6.2 Comparing Energy Requirements for German Domestic vs. Imported Green Iron Production

In 2022, Germany's total domestic electricity consumption was estimated at **1,720 PJ (478 TWh)**, while total energy imports amounted to **9,760 PJ**.[48] Meeting **10% of Germany's annual steel demand** through the import of iron ore and renewable energy for domestic **iron and steel production** (**Scenario 1**) would require **26.3 PJ of hydrogen**, equivalent to **0.27% of Germany's total energy imports** in 2022. Electricity consumption would vary, depending on which production pathway is considered, with the *Hematite Pathway* requiring **6.7 PJ (0.39% of 2022 electricity consumption)** and the *Magnetite Pathway* requiring **7.2 PJ (0.42% of 2022 electricity consumption)**.

Generating this renewable energy locally would result in capital costs in the order of **14.9-16.9 billion A$** (10.4-11.8 billion US$), assuming this energy is met by solar PV or onshore wind (see footnote[4]), before accounting for electricity firming costs. Alternatively, importing this renewable energy from Australia would incur an estimated annual cost of **3.1–4.9 billion A$**, representing potential export revenue for Australia, provided German steelmakers are willing and able to pay the market price premiums for renewable energy imports. For comparison, importing metallurgical coal to produce the same amount of iron via the conventional BF-BOF pathway would cost an estimated **0.45–0.58 billion A$**. This highlights Australia's potential to transition towards renewable energy exports, contingent on market acceptance of current price premiums (see footnote[5]).

Alternatively, **if Germany were to import green iron as an intermediate product** instead of producing it domestically (i.e., export **Scenario 2**), energy requirements would be significantly lower. Firstly, energy for reducing iron ore to iron would not be required, and electricity consumption would drop to **0.7 PJ (0.04% of 2022 electricity consumption)** for the *Hematite Pathway* and **6.0 PJ (0.35% of 2022 electricity consumption)** for the *Magnetite Pathway*. By **importing iron** instead of producing it domestically, Germany could **save approximately 26.3 PJ of energy imports for renewable hydrogen** and **reduce domestic electricity requirements by 1.2–6.0 PJ**, depending on the steelmaking pathway.

6.3 Cost Implications of Renewable Energy Imports vs. Green Iron Imports

As outlined in **Section 5.1**, the delivered cost of renewable hydrogen is estimated at **91–143 A$/GJ**. If considering **imported hydrogen costs alone**, for hydrogen-based DRI production in Germany, this amounts to an estimated **676–1,063 A$/tonne$_{\mathbf{Iron}}$**. In contrast, as outlined in **Section 5.2**The cost of exporting green iron from Australia to Germany is estimated at 782–1,147 A$/tonne. Iron for a fully decarbonised value chain and 663–896 A$/tonne. Iron for decarbonising only the ironmaking stage within a fossil-fuel-based value chain. Notably, these delivered green iron costs are either **similar to** (in the case of a fully decarbonised value chain), or **lower than** (in the case decarbonising only ironmaking), **the cost of importing renewable energy alone** for local green iron production in Germany, even **before factoring in additional cost inputs** such as iron ore and other feedstock and production costs for ironmaking in Germany.

[4] Assumes a green hydrogen specific energy consumption (SEC) of 55.5 kWh/kg$_{H_2}$ (**Appendix 8.2**), with solar PV and wind capacity factors of 16.2% and 29.0%, respectively.[49] Installed costs are estimated at 750 USD/kW for solar PV,[49] 1,583 USD/kW for onshore wind,[49] and 2160 USD/kW for electrolysers.[29] For a hydrogen demand of 26.3 PJ and electricity demand of 6.7-7.2 PJ.

[5] For a hydrogen demand of 26.3 PJ and electricity demand of 6.7-7.2 PJ and assuming no energy losses for the conversion of the energy carrier to electrical energy and a renewable energy export cost of 94-146 A$/GJ (**Section 5.1**). Equivalent coal consumption based on a coke consumption of 0.28-0.36 tonne/tonne$_{Iron}$[50-52], which translates to a metallurgical coal requirement of 0.40-0.51 tonne/tonne$_{Iron}$ assuming a coke oven yield of 70%.[53] For a metallurgical coal price of 290 A$/tonne.[54]

7 Conclusion

This report provided cost estimates for three key export scenarios through which Australia could support Germany's development of a green iron and steel industry, noting that the **first two scenarios are most viable** under existing industry structures in Australia and Germany:

> **Scenario 1**: Exporting iron ore and renewable energy to enable green iron and steel production in Germany. Meeting **10% of Germany's steel demand** under this scenario would require approximately **5.34–5.78 Mt of iron ore**, **26.3 PJ (0.219 Mt) of hydrogen gas**, and **6.67–7.20 PJ (1.84-1.99 TWh) of local energy generation** (which can be met through renewable energy exports).
>
> **Scenario 2**: Exporting green iron and renewable energy. Meeting **10% of Germany's steel** demand in this scenario would require approximately **3.85 Mt of green iron** and **0.655–6.04 PJ (0.181-1.67 TWh) of local energy generation** (which can be met through renewable energy exports).
>
> **Scenario 3**: Exporting green steel for conversion into specialty steel products in Germany. Meeting **10% of Germany's steel demand** under this scenario would require approximately **3.54 Mt** of green steel. Additional energy requirements would be needed to convert this steel to specialty steel products; however, these were not considered by this analysis.

Based on the analysis performed in this report, a summary of the delivered costs for renewable hydrogen export costs is provided in **Table 7**, showing the costs from each of the ten locations considered in this analysis to the Port of Hamburg, Germany.

Table 7. Summary of Renewable Hydrogen Delivered Costs

Renewable Hydrogen Exports	**A$/GJ**
Liquefied Hydrogen	102-143
Liquid Organic Hydrogen Carrier (LOHC)	94-127
Ammonia	91-126
Liquefied Synthetic Natural Gas	91-124

Similarly, a summary of delivered costs for iron ore, iron and steel from the ten locations considered in this analysis to the Port of Hamburg, Germany is provided in **Table 8**.

Table 8. Summary of Iron Ore, Iron and Steel Delivered Costs

Hematite Pathway	**Iron Ore[1] (A$/tonne)**	**Iron[2] (A$/tonne)**	**Steel (A$/tonne)**
Fossil Fuel Case	97-116	380-427	431-478
Green Case (Entire Value Chain Decarbonised)	184-256	832-1196	883-1255
Green Case (Only Iron and Steelmaking Decarbonised)	97-116	760-1037	812-1095
Green Case (Only Iron and Steelmaking Decarbonised) – Including A$2/kgH2 tax credit	97-116	636-913	688-971
Magnetite Pathway	**Iron Ore[1] (A$/tonne)**	**Iron[2] (A$/tonne)**	**Steel (A$/tonne)**
Fossil Fuel Case	123-140	299-349	432-486
Green Case (Entire Value Chain Decarbonised)	232-354	782-1147	934-1362
Green Case (Only Iron and Steelmaking Decarbonised)	123-140	663-896	812-1099
Green Case (Only Iron and Steelmaking Decarbonised) – Including A$2/kgH2 tax credit	123-140	539-772	688-975

3. In the *Hematite Pathway*, iron ore refers to **direct shipping ore (DSO)**, while in the *Magnetite Pathway*, iron ore refers to **DRI-grade iron ore pellets.**
4. In the *Hematite Pathway*, iron refers to a product similar to **pig iron**, while in the *Magnetite Pathway*, iron refers to **hot-briquetted iron (HBI).**

Importantly, when considering current port-side prices of iron and steel—**595 A$/tonne** for pig iron[1] and **515 A$/tonne** for HBI[2]—the delivered cost of **green iron and steel**, where only iron and steelmaking are decarbonised and a **A$2/kg$_{H_2}$ tax credit** is applied, allows green iron to be produced **close to** market rates and green steel to be produced **at or below** current market rates.

This forms the **third part** of a series of **four** reports. The first report builds the case for developing a green iron and steel value chain between Australia and Germany. The second report explores **technology pathways** for green iron and steel production, and the fourth report summarises **government, industry, and academic consultations** on the current state of play and the roadmap for developing a green iron and steel industry.

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Appendix for **Report 3**: *Cost Estimates for an Australian Germany Green Iron and Steel Value Chain*

1 Framework for Multi Criteria Analysis

The following Table S1 provided an overview of the scoring metrics used to perform the multi criteria analysis (MCA) of the locations selected in the analysis.

Table S1. Framework used for multi-criteria analysis

Metric	Description	Scoring
Proximity to iron ore reserves	Proximity to iron ore reserves was used to assess how easily iron ore could be exported or brought to iron and steelmaking facilities for processing	1- >300 km 2- <300 km 3- <150 km
Capacity of iron ore reserves	This is a measure of the capacity of the nearest iron ore reserves, serving as an indicator of both the scale and long-term viability of the associated mining operations	1- <500 Mt 2- <5000 Mt 3- >5000 Mt
Proximity to rail networks	Proximity to rail infrastructure was used to assess how easily export products could be transported.	1- >300 km 2- <300 km 3- <150 km
Proximity to port infrastructure	Proximity to port infrastructure was used to assess how easily export products could be transported.	1- >300 km 2- <300 km 3- <150 km
Proximity to major cities	Proximity to major cities was used as a proxy to assess access to human capital.	1- >500 km 2- <500 km 3- <200 km

2 Ore Extraction & Processing Model

2.1 Fossil Fuel Case Model Assumptions

Table S2. Ore Extraction Model Parameters[1]

Financial Assumptions			
Discount Rate	7	%	Assumed
Economic Life	30	years	Assumed to have a similar life to iron and steelmaking process (**Section 4**)
System Sizing			
Mine Capacity (Q_{mine})	-	tonne/year	Model input
	$\frac{Q_{mine}}{365}$	tonne/day	
Process Plant Availability	90	%	Assumed to have a similar process plant availability to the iron and steelmaking process (**Section 4**)
Mining Vehicles Utilisation Factor	92	%	A mining hauling vehicle stops for a total of 30.4 days per year [1]. Assumed similar stop times for drilling and loading equipment. See **Eq (1)** for how the utilisation factor was applied
Mine Site and Processing Capital Cost Estimates			
Processing Plant			
Crushing and Screening Plant Building Cost	0.6	-	Scale factor [2]
	1	tonne/day	Reference capacity [2]
	59,955	US$	Reference cost [2]
	85,650	A$	
Primary Crushing Plant Cost	0.7	-	Scale factor [2]
	1	tonne/day	Reference capacity [2]
	33,308	US$	Reference cost [2]
	47,583	A$	
Fine Ore Crushing and Conveyors Cost	0.7	-	Scale factor [2]
	1	tonne/day	Reference capacity [2]
	39,970	US$	Reference cost [2]
	57,100	A$	
Grinding and Storage	0.7	-	Scale factor [2]
	1	tonne/day	Reference capacity [2]
	41,524	US$	Reference cost [2]
	59,320	A$	
Beneficiation[2]	0.6	-	Scale factor [2]
	1	tonne/day	Reference capacity [2]
	45,743	US$	Reference cost [2]
	65,347	A$	
Pelletisation[2]	0.65	-	Scale factor [3]
	7,671	tonne/day	Reference capacity [3]
	360,865,773	US$	Reference cost [3]
	515,522,533	A$	
	0.5	-	Scale factor [2]

Tailings Dam Storage Cost	1	tonne/day	Reference capacity [2]
	44,411	US$	Reference cost [2]
	63,444	A$	
Drilling, Loading & Hauling Equipment			
Drilling Equipment			
Number of Drills	2	integer	2-4 drills required for a mine site of <60,000 tonnes/day [2]
Drill Diameter	5.23	inches	$\sqrt{(}Q_{mine}\ (\frac{tonne}{day})/100)$ [2]
Drilling Equipment Power Rating	25	kW/Drill	4-50kW per dill [4]
Cost of Drilling Equipment	1.8	Factor	Scale factor [2]
	1	inches	Reference drill diameter [2]
	44,411	US$	Reference Cost [2]
Loading Equipment			
Loader Capacity (Cap_{Loader})	3.44	Cubic yards	$0.145 * \left(Q_{mine}\left(\frac{ton}{day}\right)\right)^{0.4}$ [2]
Number of Loaders (n_{Loader})	2	integer	$\frac{0.011*\left(Q_{mine}\left(\frac{ton}{day}\right)\right)^{0.8}}{Cap_{Loader}\ (yards^3)}$ [2]
Loader Power Rating	120	kW/loader	117-299kW per loader [5]
Loader Equipment Cost	0.80	Factor	Scale factor [2]
	1.00	yards^3	Reference loader capacity [2]
	1,132,479	US$	Reference loader equipment cost [2]
	1,617,827	A$	
Hauling Equipment			
Hauling Truck Capacity (Cap_{Truck})	35	tonne	$9 * (n_{Loader})^{1.1}$ [2]
Number of Hauling Trucks (n_{Trucks})	5	integer	$\frac{0.25*\left(Q_{mine}\left(\frac{ton}{day}\right)\right)^{0.8}}{Cap_{Truck}\ (ton)}$ [2]
Hauling Truck Power Rating	8	(kW/tonne)/truck	8-9.5kW/tonne per hauling truck. Based on 265-2983kW per hauler for capacities of 28-372tonnes [6, 7]
Truck Equipment Cost	0.90	-	Scale factor [2]
	1	tonne	Reference Truck Capacity [2]
	45,299	US$	Reference Cost [2]
	64,713	A$	
Mine Site and Processing Operating Cost Estimates			
Staffing Costs			
Number of Mining Personnel (n_{Mining})	19	integer	$0.034 * \left(Q_{mine}\ \left(\frac{tonne}{day}\right)\right)^{0.8}$ [2]
Number of Mill Personnel ($n_{Milling}$)	77	integer	$7.2 * \left(Q_{mine}\ \left(\frac{tonne}{day}\right)\right)^{0.3}$ [2]
Number of Service Personnel ($n_{Service}$)	24	integer	$0.254 * (n_{Mining} + n_{Milling})$ [2]

Number of Administrative Personnel (n_{Admin})	13	integer	$0.11 * (n_{Mining} + n_{Milling} + n_{Service})$ [2]
Annual hours worked per worker	1920	(hrs/worker)/yr	Estimated based on a 40 hour week and 48 weeks per year
Average worker hourly wage	-	US$/hr	Refer to **Section 10**
Explosives Costs			
Explosives Requirements	0.50	$kg_{ANFO}/tonne_{ore}$	Assuming the use of Ammonium Nitrate Fuel Oil (ANFO) [8]
Explosives Cost	-	$US\$/tonne_{ANFO}$	Refer to **Section 10**
Electricity Costs			
Electricity Requirements for Crushing, Grinding & Screening	25	$kWh/tonne_{ore}$	Based on an electricity consumption rate for Crushing, Grinding & Screening of 20-30 $kWh/tonne_{ore}$ [9]
Electricity Requirements for Beneficiation[2]	0.85	$kWh/tonne_{ore}$	Electricity requirements for beneficiation [10]
Electricity Requirements for Pelletisation[2]	30	$kWh/tonne_{ore}$	Based on an electrical energy consumption of 25-35 kWh/tonne [11]
Electricity Cost	-	USD/kWh	Refer to **Section 10**
Diesel Fuel Costs for Drilling, Loading & Hauling Equipment			
Diesel Engine Fuel Efficiency (ε_{Engine})	40	%	Based on typical diesel engine efficiency of 30-45% [12]
Diesel Costs	-	USD/kWh	Refer to **Section 10**
Fuel Costs for Pelletisation			
Thermal Energy Requirements for Pelletisation[2]	250	$kWh/tonne_{ore}$	Based on a thermal energy consumption of 97-416 kWh/tonne [11]. Base case assumed this energy is provided by natural gas
Natural Gas Costs	-	US$/kWh	Refer to **Section 10**
Carbon Emissions Factors			
Grid Electricity Emissions	-	$kgCO_2eq/kWh$	Refer to **Section 9**
Diesel Fuel Emissions	-	$kgCO_2eq/kWh$	Refer to **Section 9**
Natural Gas Emission	-	$kgCO_2eq/kWh$	Refer to **Section 9**
Explosive Emissions	-	$kgCO_2eq/kg_{ANFO}$	Refer to **Section 9**

1. Where applicable, dollar values have been adjusted to 2024 values. Values pertaining to plant or equipment costs were adjusted using CEPCI indices [13]. Costs pertaining to insurance, labour or personnel costs, were adjusted using a 3% annual CPI increase. Costs that were adjusted using a CPI increase have been stated above in the table.
2. Beneficiation and Pelletisation assumed for the mining of magnetite ore only

Fuel consumption rates for mine site vehicles (β) were determined based on the following equation:

$$\beta = \frac{P * f * \frac{24hr}{day} * \frac{365day}{yr}}{\varepsilon} \qquad \textbf{Eq (1)}$$

Where:

$\beta = Fuel\ Consumption\ (\frac{kWh}{yr})$

$P = Vehicle\ Power\ Rating\ (kW)$

$f = Mining\ Vehicle\ Utilisation\ Factor\ (\%)$

$\varepsilon = Tank\ to\ Wheel\ Efficiency\ (\%)$

2.2 Decarbonisation Assumptions

The use of hydrogen fuel cell electric and battery electric mining vehicles were considered for process decarbonisation as these are widely recognised decarbonisation options for heavy-duty vehicles [14]. However, as hydrogen powered and battery powered mining vehicles are not yet widely commercially available, costing estimates for these vehicles followed a similar methodology to Ahluwalia *et al.* which was used to estimate the cost of hydrogen-powered heavy-duty road vehicles [15]. The capital cost of the hydrogen powered ($Z_{H2\,Vehicle}$), and battery powered ($Z_{BAT\,Vehicle}$) mining vehicles was thus determined as follows:

$$Z_{H2\,Vehicle} = Z_{Diesel} - Z_{DieselDT} + Z_{ElecDT} + Z_{BAT} + Z_{FC} + Z_{H2Tank}$$
$$Z_{BAT\,Vehicle} = Z_{Diesel} - Z_{DieselDT} + Z_{ElecDT} + Z_{BAT} \qquad \textbf{Eq (2)}$$

Where:

$Z_{Diesel} = Diesel\ vehicle\ capital\ cost\ (USD)$

$Z_{DieselDT} = Diesel\ vehicle\ drive\ train\ capital\ cost\ (USD)$

$Z_{ElecDT} = Electric\ vehicle\ drive\ train\ capital\ cost\ (USD)$

$Z_{BAT} = Battery\ capital\ cost\ (USD)$

$Z_{FC} = Fuel\ cell\ capital\ cost\ (USD)$

$Z_{H2Tank} = Hydrogen\ storage\ capital\ cost\ (USD)$

Cost estimates used to determine battery electric and hydrogen fuel cell mining vehicles has been provided in the following **Table S3.**

Table S3. Cost Estimates for Battery Electric and Hydrogen Fuel Cell Mining Truck Cost Estimation[1]

Parameter	Value	Unit	Notes
Battery Electric Mining Vehicle Cost			
Diesel Drivetrain Cost	95	US$/kW	Based on the price of a diesel engine (80USD/kW) plus diesel drivetrain (15USD/kW) [15]
	135	A$/kW	
Electric Drivetrain Cost	30	US$/kW	Based on the price of an electric drivetrain [15]
	43	A$/kW	
Battery Electric Vehicle Battery Cost	247	US$/kWh	Based on current lithium-ion battery costs [16]
	353	A$/kWh	
Battery Electric Vehicle Battery Capacity	15	h	Assuming ample battery capacity to allow for typical stop time of twice per 24 hours for refuelling [1] and to allow for a distance range of down to 20% [14]
Battery Electric Vehicle Tank to Wheel Efficiency	80	%	Accounts for both battery and drivetrain efficiency. Range spans from 64.4-86% [14]
Hydrogen Fuel Cell Mining Vehicle Cost			
Diesel Drivetrain Cost	95	US$/kW	Based on the price of a diesel engine (80US$/kW) plus diesel drivetrain (15US$/kW) [15]
	135	A$/kW	
Electric Drivetrain Cost	30	US$/kW	Based on the price of an electric drivetrain [15]
	43	A$/kW	
Hydrogen Fuel Cell Vehicle Battery Cost	247	US$/kWh	Based on current lithium-ion battery costs [16]
	353	A$/kWh	
Hydrogen Fuel Cell Battery Capacity	0.15	h	Calculated based on battery capacity of fuel cell vehicles [17]
Hydrogen Fuel Cell Cost	5,636	US$/kW	Based on current hydrogen fuel cell cost estimates [16]
	8,052	A$/kW	
Hydrogen Fuel Cell Vehicle Storage Cost	27	US$/kWh	Based on 35 MPa hydrogen storage tanks [18]
	39	A$/kWh	
Hydrogen Storage Tank Capacity	15	h	Assumed same energy storage requirements as the battery electric vehicle
Overall Vehicle Efficiency	55	%	Based on Low Heat Value (LHV) efficiency [10, 18]
Hydrogen Fuel Cell Tank to Wheel Efficiency	44	%	Estimate based on fuel cell efficiency and battery electric efficiency. Refer to **Eq (3)**

1. Where applicable, dollar values have been adjusted to 2024 values using CEPCI indices [13]

Hydrogen fuel cell vehicles use electric motors driven by a small battery, powered by a hydrogen fuel cell. The tank-to-wheel efficiency (ε_{HFCEV}) was thus calculated using the fuel cell efficiency and the efficiency of the battery electric drivetrain through the following equation:

$$\varepsilon_{HFCEV} = \varepsilon_{HFC} * \varepsilon_{BEV} \qquad \textbf{Eq (3)}$$

Where:

$\varepsilon_{HFCEV} = Hydrogen\ Fuel\ Cell\ Vehicle\ Tank\ to\ Wheel\ Efficiency\ (\%)$

$\varepsilon_{HFC} = Hydrogen\ Fuel\ Cell\ Efficiency\ (\%)$

$\varepsilon_{BEV} = Battery\ Electric\ Vehicle\ Tank\ to\ Wheel\ Efficiency\ (\%)$

Pelletisation was applied for the processing of magnetite ore. The pelletisation process relies on a two energy streams, one to provide electrical energy for the process and the other to provide thermal energy. The decarbonisation options assumed that thermal energy was derived from either electrical energy or hydrogen. The use of hydrogen or electrical energy assumed no change in capital costs for the pelletisation process. Electrical energy requirements for the process were assumed to be unchanged for the decarbonisation options.

Table S4. Pelletisation Decarbonisation Assumptions

Thermal Energy for Pelletisation			
Thermal Energy Requirements for Pelletisation	250	$kWh/tonne_{ore}$	Based on a thermal energy consumption of 97-416 kWh/tonne [11]. Decarbonisation assumed this was delivered by electricity or hydrogen.
Electrical Energy for Pelletisation			
Electricity Requirements for Pelletisation	30	$kWh/tonne_{ore}$	Based on an electrical energy consumption of 25-35 kWh/tonne [11]. Assumed unchanged for each decarbonisation option.

3 Rail Transport Model

3.1 Fossil Fuel Case Model Assumptions

Table S5. Rail Transport Model Parameters[1]

Financial Assumptions			
Discount Rate	7	%	Assumed
Economic Life	20	years	Based on the useful life of a locomotive [18]
Journey Assumptions			
One-way distance travelled by rail	-	km	Refer to **Section 10**
Total time to load train	3.0	hrs	Assumed equivalent to unloading time
Total time to unload train	3.0	hrs	Based on typical iron ore train unloading time [19]
Average speed	70	km/h	Based on locomotive speed of up to 80 km/h [20]
Days per year in operation	350	days	Assumed to operate on a similar schedule to the shipping analysis (**Section 4**)
Diesel Locomotive & Wagon Capital Cost Assumptions			
Wagon Capacity	110	tonne/wagon	Based on a wagon capacity of 105-110 tonne/wagon [21, 22]
Wagon Length	16.1	m/wagon	Based on the coupled length of 2 coal wagons (32.3m) [23]. Assuming similar to that of an iron ore wagon
Number of wagons per train	230	integer	Based on a train capacity of 226-270 wagons/train [22, 24]
Wagon cost	150,000	US$/wagon	Based on a wagon cost of 100,000-188,000 US$/wagon [25, 26]
	214,286	A$/wagon	
Wagon empty weight	21.7	tonne/wagon	Based on the tare weight of a coal wagon [23]. Assuming similar to that of an iron ore wagon
Number of locomotives per train	4	integer	Typically 3-4 locomotives per train [24, 27]
Locomotive Length	15	m/locomotive	Based on the coupled length of a diesel locomotive (12-17.8m) [23]
Locomotive cost	3,940,000	US$/locomotive	Diesel locomotive cost [18]
	5,628,571	A$/locomotive	
Locomotive empty weight	123.7	tonne	Diesel locomotive tare weight [28]
Maintenance & repair	7.08	(US$/km)/locomotive	Diesel locomotive repair costs [18]
	10	(A$/km)/locomotive	

Energy consumption	0.117	kWh/tonne.km	Based on diesel locomotive operating on gentle topography [28]
Operating Cost Assumptions			
Flag-fall rail access fee	2.8	US$/km	Heavy freight price per train kilometre [29]
	4	A$/km	
Variable rail access fee	0.0054	US$/tonne.km	Variable rail access fee per gross tonne kilometre [29]
	0.008	A$/tonne.km	
Wagon maintenance & repair	0.06	(US$/km)/wagon	Wagon maintenance and repair per kilometre [25]
	0.086	(A$/km)/wagon	
Rail network maintenance & repair	0.002	US$/tonne.km	Rail network maintenance per gross tonne kilometre [25]
	0.003	A$/tonne.km	
Cargo insurance	0.001	US$/tonne.km	Insurance per net tonne kilometre is only paid for the payload of ore, and is not applied to the return leg [25]. Value escalated to present day using a 3% annual CPI increase
	0.001	A$/tonne.km	
Shift positions required	2	integer	Standard 2-person crew for train operation [25, 30]
Shift position multiplier	4.8	worker/shift position	Used to estimate the number of people to staff each shift position [31]
Annual hours worked per worker	1920	(hrs/worker)/yr	Estimated based on a 40 hour week and 48 weeks per year
Average worker hourly wage	-	US$/hr	Refer to **Section 10**
Carbon Emissions Factors			
Diesel Fuel Emissions	-	$kgCO_2eq/kWh$	Refer to **Section 9**

1. Where applicable, dollar values have been adjusted to 2024 values. Values pertaining to plant or equipment costs were adjusted using CEPCI indices [13]. Costs pertaining to insurance, labour or personnel costs, were adjusted using a 3% annual CPI increase. Costs that were adjusted using a CPI increase have been stated above in the table.

3.2 Decarbonisation Assumptions

Decarbonisation of the rail transport model considered the use of electric locomotives (powered by overhead catenary lines), battery electric locomotives, and hydrogen fuel cell locomotives, as these are widely recognised decarbonisation options for heavy-duty rail freight [18, 24, 32]. A comparison of the model assumptions for electric, battery electric, and hydrogen fuel cell locomotives is provided in **Table S6**.

Table S6. Model Assumptions for Diesel, Electric and Hydrogen Fuel Cell Locomotives[1]

Electric Locomotive			
Locomotive cost	5,470,000	US$/locomotive	Electric locomotive cost [18]
	7,814,286	A$/locomotive	
Locomotive empty weight	138.0	tonne	Electric locomotive tare weight [28]
Maintenance & repair	4.04	(US$/km)/locomotive	Electric locomotive repair costs [18]
	6	(A$/km)/locomotive	
Energy consumption	0.052	kWh/tonne.km	Based on electric locomotive operating on gentle topography [28]
Catenary line installation	2,350,000	US$/km	Catenary line (overhead powerlines) installation necessary for electric locomotive operation [18]
	3,357,143	A$/km	
Battery Electric Locomotive			
Locomotive cost	-	US$/locomotive	Refer to estimates below
Locomotive empty weight	172.0	tonne	Mass of an electric locomotive plus the weight of a 5,100 kWh battery pack (**Table S5**) at an energy density of 150 Wh/kg [18]
Maintenance & repair	4.04	(US$/km)/locomotive	Assumed equivalent to electric locomotive maintenance and repair
	6	(A$/km)/locomotive	
Energy consumption	0.052	kWh/tonne.km	Based on electric locomotive operating on gentle topography [28]
Hydrogen Fuel Cell Locomotive			
Locomotive cost	-	US$/locomotive	Refer to estimates below
Locomotive empty weight	138.0		Assumed equivalent to electric locomotive tare weight
Maintenance & repair	4.04	(US$/km)/locomotive	Assumed equivalent to electric locomotive maintenance and repair
	6	(A$/km)/locomotive	
Energy consumption	-	kWh/tonne.km	Refer to **Table S8**

1. Where applicable, dollar values have been adjusted to 2024 values using CEPCI indices [13]

As battery electric locomotives are not yet widely commercially available, costing estimates for these vehicles followed a similar methodology to Zenith *et al.* [18]. The capital cost of the battery electric locomotive ($Z_{Battery}$) was thus determined as follows:

$$Z_{Battery\ Locomotive} = Z_{Electric} + Z_{BAT} \quad \textbf{Eq (4)}$$

Where:

$Z_{Battery\ Locomotive} = Battery\ Electric\ Locomotive\ Capital\ Costs\ (USD)$

$Z_{Electric} = Electric\ Locomotive\ Capital\ Costs\ (USD)$

$Z_{BAT} = Battery\ Capital\ Costs\ (USD)$

Table S7. Rail Transport Model Parameters for Battery Electric Locomotive Current Cost Estimates

Parameter	Value	Unit	Notes
Battery Cost	247	US$/kWh	Based on current lithium-ion battery costs [16].
	353	A$/kWh	
Battery Capacity	14,500	kWh	Based on battery wagon energy capacity of battery electric locomotives ordered by BHP, the Australian iron ore mining company [24]

As hydrogen powered locomotives are not yet commercially available, costing estimates for these vehicles followed a similar methodology to Zenith *et al.* [18]. The capital cost of the hydrogen powered locomotive ($Z_{H2\ Locomotive}$) was thus determined as follows:

$$Z_{H2\ Locomotive} = Z_{Electric} + Z_{BAT} + Z_{FC} + Z_{H2Tank} \quad \textbf{Eq (5)}$$

Where:

$Z_{H2\ Locomotive} = Hydrogen\ Fuel\ Cell\ Locomotive\ Capital\ Costs\ (USD)$

$Z_{BAT} = Battery\ Capital\ Cost\ (USD)$

$Z_{FC} = Fuel\ Cell\ Capital\ Cost\ (USD)$

$Z_{H2Tank} = Hydrogen\ Storage\ Capital\ Cost\ (USD)$

Hydrogen powered locomotive energy consumption ($\beta_{H2\ Locomotive}$) was based on the energy consumption of an electric locomotive and the efficiency of the hydrogen fuel cell, as provided by the following equation:

$$\beta_{H2\ Locomotive} = \frac{\beta_{Electric\ Locomotive}}{\varepsilon_{HFC}} \qquad \textbf{Eq (6)}$$

Where:

$\beta_{H2\ Locomotive} = Hydrogen\ Locomotive\ Energy\ Consumption\ (\frac{kWh}{tonne.km})$

$\beta_{Electric\ Locomotive} = Electric\ Locomotive\ Energy\ Consumption\ (\frac{kWh}{tonne.km})$

$\varepsilon_{HFC} = Hydrogen\ Fuel\ Cell\ Efficiency\ (\%)$

Table S8. Rail Transport Model Parameters for Hydrogen Fuel Cell Locomotive Current Cost Estimates

Parameter	Value	Unit	Notes
Hydrogen Fuel Cell Vehicle Battery Cost	247	US$/kWh	Based on current lithium-ion battery costs [16]
	353	A$/kWh	
Hydrogen Fuel Cell Battery Capacity	2	kWh	Based on battery capacity of fuel cell vehicles [17]
Hydrogen Fuel Cell Cost	5,636	US$/kW	Based on current hydrogen fuel cell cost estimates [16]
	8,052	A$/kW	
Locomotive Power	3,280	kW	Electric locomotive power [18]
Hydrogen Fuel Cell Vehicle Storage Cost	27	US$/kWh	Based on 35 MPa hydrogen storage tanks [18]
	39	A$/kWh	
Hydrogen Storage Tank Capacity	38,800	kWh	Based on a diesel locomotive tank capacity of 4,000L [23] and a diesel energy density of 9.7 kWh/L
Hydrogen Fuel Cell Efficiency	55	%	Based on Low Heat Value (LHV) efficiency [10, 18]
Hydrogen Fuel Cell Locomotive Fuel Consumption	0.095	kWh/tonne.km	Refer to equation **Eq (6**)

4 Dry-Bulk and Break-Bulk Shipping Model

The following model assumptions were used to model the export of iron ore, iron and steel.

4.1 Fossil Fuel Case Model Assumptions

Table S9. Shipping Model Parameters[1]

Financial Assumptions			
Discount Rate	7	%	Assumed
Economic Life	30	years	Based on typical maritime vessel useful life (25-30 years) [33]
Journey Assumptions			
One-way shipping distance	-	Nautical Miles	Refer to **Section 10**
Days per year in operation	350	days/year	Based on prior shipping analysis [34]
Suez Canal cost	400,000	US$	One-way canal cost [34]
	571,429	A$	
Panama Canal cost	350,000	US$	One-way canal cost [34]
	500,000	A$	
Time to load/unload vessel	3,000	tonne/hr	Average ship dry-bulk loading rate: 2,500-3,000 tonne/hr [19]
Port pilotage charges	15,291	US$/vessel	Cost to dock at port, includes cost to load and unload ship [35]
	21,844	A$/vessel	
Port tonnage charges	0.35	US$/tonne	Port tonnage charges [35]
	0.50	A$/tonne	
Port wharfage charges	1.86	US$/tonne	Wharfage charges [35]
	2.66	A$/tonne	
Port berthage charges	315	US$/hr	Berthage charge: 252-315 US$/hr [35]
	450	A$/hr	
Ship Characteristics			
Vessel type	HandyCape	-	Assumed this vessel type as dry bulk and break bulk carriers to transport iron ore, HBI and steel are generally shipped in vessels (>100,000 dwt) [36]. Assumed vessel can pass the Suez canal based on the following restrictions of the Suez canal (Length: no limitation, Beam: 70m, Draft: 17m) [37].
Draft	15	m	Draft [38]
Beam	43	m	Beam [38]
Length	240	m	Length [38]
Dead weight tonnage (dwt)	120,000	tonne	Ship capacity [38]
Installed power	13.5	MW	Ship engine capacity [38]
Design speed	15	knots	Vessel average sailing speed [38]
Engine fuel type	Heavy Fuel Oil	-	Assumed
Fuel energy content	40.4	MJ/kg	Heavy Fuel Oil (HFO) energy content [39]

Engine fuel efficiency	40	%	Based on typical diesel engine efficiency of 30-45% [12]
Ship Cost Assumptions			
Capital cost	55,223,523	US$	New build cost based on literature value [38]. Value aligns with current quoted market prices [40]
	78,890,747	A$	
Stores and consumables	405,058	US$/year	Stores and consumables [41]. Values escalated to present day using a 3% annual CPI increase
	578,654	A$/year	
Maintenance and repairs	375,625	US$/year	Maintenance and repairs [41].
	536,607	A$/year	
Insurance	438,696	US$/year	Insurance [41]. Values escalated to present day using a 3% annual CPI increase
	626,709	A$/year	
General costs	377,027	US$/year	General costs [41]. Values escalated to present day using a 3% annual CPI increase
	538,610	A$/year	
Periodic maintenance	588,666	US$/year	Periodic maintenance [41].
	840,951	A$/year	
Crew requirements	20	integer	Crew requirements of 20-25 personnel per vessel [42]. Assuming shifts are managed between personnel on-board.
Annual hours worked per worker	1920	(hrs/worker)/yr	Estimated based on a 40 hour week and 48 weeks per year
Average worker hourly wage	-	US$/hr	Refer to **Section 10**
Carbon Emissions Factors			
Heavy Fuel Oil Emissions	-	$kgCO_2eq/kg_{Fuel}$	Refer to **Section 9**

1. Where applicable, dollar values have been adjusted to 2024 values. Values pertaining to plant or equipment costs were adjusted using CEPCI indices [13]. Costs pertaining to insurance, labour or personnel costs, were adjusted using a 3% annual CPI increase. Costs that were adjusted using a CPI increase have been stated above in the table.

4.2 Decarbonisation Assumptions

The use of ammonia and methanol fuel were considered for process decarbonisation as these are widely recognised decarbonisation options for the maritime industry [43]. Capital costs of the ammonia and methanol powered ships were assumed to be similar to that of the diesel powered ships owing to the similar drivetrain technology employed for both [34]. A comparison of the model assumptions for ammonia and methanol shipping fuel is provided in **Table S10**.

Table S10. Model Assumptions for Ammonia and Methanol Powered Ships.

Ammonia Case			
Engine fuel type	Ammonia	-	
Fuel energy content	18.8	MJ/kg	Ammonia energy content [44]
Engine fuel efficiency	35	%	Based on an ammonia combustion engine efficiency of 31-39% [45]
Diesel engine cost	449	US$/kW	New build diesel engine cost [46]
	641	A$/kW	
Ammonia engine cost	898	US$/kW	New build ammonia dual fuel engine cost [46]
	1,283	A$/kW	
Ammonia tank and scrubber costs	673	US$/kW	New build ammonia tank and scrubber costs [46]
	961	A$/kW	
Ammonia combustion emissions	-	$kgCO_2eq/kg_{Fuel}$	Refer to **Section 9**
Methanol Case			
Engine fuel type	Methanol	-	
Fuel energy content	19.9	MJ/kg	Methanol energy content [46]
Engine fuel efficiency	40	%	Based on a methanol combustion engine efficiency of 33-43% [47]
Diesel engine cost	449	US$/kW	New build diesel engine cost [46]
	641	A$/kW	
Methanol engine cost	673	US$/kW	New build methanol dual fuel engine cost [46]
	961	A$/kW	
Methanol tank costs	224	US$/kW	New build methanol tank costs [46]
	320	A$/kW	
Methanol combustion emissions	-	$kgCO_2eq/kg_{Fuel}$	Refer to **Section 9**

The capital costs of the ammonia-powered and methanol-powered vessels were determined using a methodology employed by Lindstad *et al.* [46]. The new build cost of a conventional shipping vessel was considered, accounting for the difference in combustion engine and storage tank costs relative to the a conventional diesel-powered engine:

$$Z_{Ammonia} = Z_{Conventional} - Z_{DieselEngine} + Z_{AmmoniaEngine} + Z_{AmmoniaTank\&Scrubber}$$

$$Z_{Methanol} = Z_{Conventional} - Z_{DieselEngine} + Z_{MethanolEngine} + Z_{MethanolTank}$$

Eq (7)

Where:

$Z_{Ammonia} = Ammonia\ powered\ vessel\ new\ build\ cost\ (USD)$

$Z_{Conventional} = Diesel\ powered\ vessel\ new\ build\ cost\ (USD)$

$Z_{DieselEngine} = Diesel\ engine\ new\ build\ cost\ (USD)$

$Z_{AmmoniaEngine} = Ammonia\ engine\ new\ build\ cost\ (USD)$

$Z_{AmmoniaTank\&Scrubber} = Ammonia\ tank\ and\ scrubber\ new\ build\ cost\ (USD)$

$Z_{Methanol} = Methanol\ powered\ vessel\ new\ build\ cost\ (USD)$

$Z_{MethanolEngine} = Methanol\ engine\ new\ build\ cost\ (USD)$

$Z_{MethanolTank} = Methanol\ tank\ new\ build\ cost\ (USD)$

5 Renewable Energy Shipping Model

The shipping of renewable energy (in the form of hydrogen and its derivatives) was modelled based on our groups previous work [34], using the HySupply Shipping Analysis Tool V1.1 [48]

5.1 Model Assumptions

The following model assumptions were input into the model to estimate the cost of shipping renewable energy from Australia to Germany.

Table S11. Model Assumptions for Renewable Energy Shipping Model.

Financial Assumptions			
Discount Rate	7	%	Assumed
Economic Life	30	years	Based on typical maritime vessel useful life (25-30 years) [33]
Journey Assumptions			
One-way shipping distance	-	Nautical Miles	Refer to **Section 10**
Days per year in operation	350	days/year	Based on prior shipping analysis [34]
Suez Canal cost	400,000	US$	One-way canal cost [34]
	571,429	A$	
Panama Canal cost	350,000	US$	One-way canal cost [34]
	500,000	A$	
Port days	1.5	days	Time taken to load/unload ship [34]
Port charges	200,000	US$	Cost to dock at port and load and unload vessel [34]
	285,714	A$	
Ship Characteristics			
Installed power	30.5	MW	Ship engine capacity [34]
Design speed	18	knots	Vessel average sailing speed [34]
Engine fuel type	Heavy Fuel Oil	-	Assumed
Fuel energy content	40.4	MJ/kg	Heavy Fuel Oil (HFO) energy content [39]
Engine fuel efficiency	40	%	Based on typical diesel engine efficiency of 30-45% [12]
Ship Cost Assumptions			
LNG carrier capital cost	192,000,000	US$	Vessel cost [34].
	274,285,714	A$	
LNG carrier capacity	160,000	m^3	Vessel capacity [34].
Transport BOG	0.17	%/day	Transport boil off gas [34].
Ammonia carrier capital cost	162,000,000	US$	Vessel cost [34].
	231,428,571	A$	
Ammonia carrier capacity	160,000	m^3	Vessel capacity [34].
Transport BOG	0.004	%/day	Transport boil off gas [34].
LOHC carrier capital cost	114,200,000	US$	Vessel cost [34]. Includes capital cost of carrier fluid of 49.2 MUS$ (based on a price of 400US$/tonne [49])
	163,142,857	A$	

LOHC carrier capacity	160,000	m^3	Vessel capacity [34].
Transport BOG	0.00	%/day	Transport boil off gas [34].
Liquid hydrogen carrier capital cost	216,000,000	US$	Vessel cost [34].
	308,571,429	A$	
Liquid hydrogen carrier capacity	160,000	m^3	Vessel capacity [34].
Transport BOG	0.20	%/day	Transport boil off gas [34].
Maintenance costs	4	% CAPEX	Annual maintenance costs [34].
Miscellaneous costs	10	% OPEX	Annual miscellaneous costs [34].
Insurance	10	% OPEX	Annual insurance costs [34].
Labour costs	2,500,000	US$/yr	Annual labour costs [34].
	3,571,429	A$/yr	
Import and Export Bunker Assumptions			
LNG bunker cost	0.6	-	Scale factor [34].
	180,000	m^3	Reference capacity [34].
	85,000,000	US$	Reference cost [34].
	121,428,571	A$	
	320,000	m^3	Nominal capacity [34].
	0.01	%/day	Storage boil-off gas rate. Assumed same as ammonia and LOHC [50]
Ammonia bunker cost	0.6	-	Scale factor [34].
	87,977	m^3	Reference capacity [34].
	25,000,000	US$	Reference cost [34].
	35,714,286	A$	
	320,000	m^3	Nominal capacity [34].
	0.01	%/day	Storage boil-off gas rate [50]
LOHC bunker cost	0.6	-	Scale factor [34].
	110,000	m^3	Reference capacity [34].
	42,350,000	US$	Reference cost [34].
	60,500,000	A$	
	320,000	m^3	Nominal capacity [34].
	0.01	%/day	Storage boil-off gas rate [50]
Liquid hydrogen bunker cost	0.6	-	Scale factor [34].
	100,000	m^3	Reference capacity [34].
	106,300,000	US$	Reference cost [34].
	151,857,143	A$	
	320,000	m^3	Nominal capacity [34].
	0.07	%/day	Storage boil-off gas rate [50]
Operation and maintenance	3	% CAPEX	Applied to all tanks. [50]

6 Ironmaking Model

6.1 Fossil Fuel Case Model Assumptions

Table S12. Ironmaking Model Parameters[1]

Financial Assumptions			
Discount Rate	7	%	Assumed
Economic Life	30	years	Based on prior project life of a green steel plant [51]
System Sizing			
Process plant design capacity ($Q_{Product}$)	-	tonne$_{HotMetal}$/year	Model input
Plant availability	90	%	Based on prior steel plant capacity factor [51]
Ironmaking Cost Estimates and Input Assumptions			
Shaft Furnace			
Shaft furnace sizing	-	tonne$_{HotMetal}$/year	Based on process plant design capacity ($Q_{Product}$) per annual hot metal production
Shaft furnace capital cost	0.6538	-	Scale factor [51]
	8.76	tonne$_{HotMetal}$/year	Reference capacity [51]
	47,841	US$	Reference cost [51]
	68,344	A$	
Annual maintenance cost	1.5	% CAPEX	Shaft furnace annual maintenance cost [52]
Electricity (DRI process)	70	kWh/tonne$_{HotMetal}$	Overall DRI process electricity requirements [53]
Iron ore	1.42-1.58	tonne$_{Ore}$/tonne$_{HotMetal}$	Calculated based on iron ore grade of 60-67% and metallic Fe content of the final product of 95%
Natural gas	0.20	tonne$_{gas}$/tonne$_{HotMetal}$	Natural gas requirements (0.17-0.23 tonne$_{gas}$/tonne) [51, 54]
Oxygen gas	3	kg/tonne$_{HotMetal}$	Oxygen requirements for DRI process [51]
Reformer			
Reformer sizing	0.71	MWh/tonne$_{HotMetal}$	Calculated based on energy requirements of syngas production [51]
Reformer capital cost	0.6505	-	Scale factor [51]
	1.0	MW	Reference capacity [51]
	4,806,408	US$	Reference cost [51]
	6,866,297	A$	
Annual maintenance cost	1.5	% CAPEX	Reformer annual maintenance cost [52]
Recycle Compressor			
Compressor sizing	0.023	MWh/tonne$_{HotMetal}$	Calculated based on energy requirements of recycle gas [51]

Compressor capital cost	0.7100	-	Scale factor [51]
	1.0	MW	Reference capacity [51]
	5,995,914	US$	Reference cost [51]
	8,565,591	A$	
Annual maintenance cost	1.5	% CAPEX	Compressor annual maintenance cost [52]
Cooling Tower			
Cooling tower sizing	1.0	$m^3/tonne_{HotMetal}$	Cooling water requirements (0.9-1.3 m^3/tonne) [51, 54]
Cooling tower capital costs	0.6303	-	Scale factor [51]
	8760	m^3/year	Reference capacity based on cooling water flowrate [51]
	59,277	US$	Reference cost [51]
	84,681	A$	
Annual maintenance cost	1.5	% CAPEX	Cooling tower annual maintenance cost [52]
Oxygen Pressure Swing Adsorption (PSA)			
Oxygen PSA sizing	-	$tonne_{O2}/tonne_{HotMetal}$	Determined by summing all unit process oxygen requirements
Oxygen PSA capital costs	0.6357	-	Scale factor [51]
	8.76	$tonne_{O2}$/year	Reference capacity [51]
	29,849	US$	Reference cost [51]
	42,641	A$	
Annual Maintenance Cost	2.5	% CAPEX	Oxygen PSA annual maintenance cost [55]
Electricity (Oxygen PSA)	385	$kWh/tonne_{O2}$	PSA oxygen generation electricity consumption [53]
Roller Press (Hot-Briquetted Iron Production)[2]			
Roller press sizing	-	$tonne_{HotMetal}$/year	Based on process plant design capacity ($Q_{Product}$) per annual hot metal production
Roller press capital costs	0.9	-	Scale factor, assumed.
	438,000	$tonne_{HBI}$/year	Capacity of HBI roller press [56]
	80,000	US$	Reference cost of HBI roller press [56]
	114,286	A$	
Annual maintenance cost	1.5	% CAPEX	Assumed similar to shaft furnace
Electricity (HBI production)	10	$kWh/tonne_{HBI}$	HBI briquette compression [10]
Electric Smelting Furnace (ESF)[3]			
ESF sizing	-	$tonne_{HotMetal}$/year	Based on process plant design capacity ($Q_{Product}$) per annual hot metal production
ESF capital costs	0.8	-	Scale factor. Assumed similar to an Electric Arc Furnace [55]
	4,920,000	tonne/yr	Reference capacity. Assumed similar to an Electric Arc Furnace [55]
	575,105,392	US$	Reference cost. Assumed similar to an Electric Arc Furnace [55]
	821,579,131	A$	

Annual maintenance cost	3	% CAPEX	Assumed similar to an Electric Arc Furnace annual maintenance cost (includes refractory lining) [57]
Slag production	0.20	$tonne_{Slag}/tonne$	Assumed similar to the slag production from an Electric Arc Furnace [52]
Electricity (ESF process)	380	$kWh/tonne_{HotMetal}$	Electricity requirements, assumed similar to the operation of an EAF (355-380 kWh/tonne) if hot-linked, (453 kWh/tonne) if not hot-linked [51, 53]
Carbon addition for ESF process	0.027	$tonne_{C}/tonne_{HotMetal}$	Carbon addition for ESF operation. Assumed similar to Electric Arc Furnace [51]
Lime addition for ESF process	0.05	$tonne_{Lime}/tonne_{HotMetal}$	Lime addition for ESF operation. Assumed similar to Electric Arc Furnace (0.04-0.05 $tonne_{Lime}/tonne$) [51, 53]
Continuous Casting			
Casting sizing	-	$tonne_{HotMetal}/year$	Based on process plant design capacity ($Q_{Product}$) per annual hot metal production
Casting capital costs	0.8	-	Scale factor. Based on continuous slab caster [55]
	4,000,000	tonne/yr	Reference capacity. Based on continuous slab caster [55]
	190,077,206	US$	Reference cost. Based on continuous slab caster [55]
	271,538,866	A$	
Annual maintenance cost	8	% CAPEX	Continuous casting annual maintenance cost [55]
Electricity (continuous casting)	10	$kWh/tonne_{HotMetal}$	Continuous casting electricity requirements [58]
Overall Process Input Costs			
Carbon cost	-	$US\$/tonne_{C}$	Cost for carbon used for ESF addition. Refer to **Section 10**
Lime cost	-	$US\$/tonne_{Lime}$	Cost for lime used for ESF addition. Refer to **Section 10**
Slag waste management	-	$US\$/tonne_{Slag}$	Cost for slag waste management for ESF. Refer to **Section 10**
Operation and Labour Cost Estimates			
DRI process operation	4	integer	Assuming 4 shift positions for the operation of the DRI process [31]
ESF Process operation	4	integer	Assuming 4 shift positions for the operation of the ESF process [31]

HBI/Pig Iron Storage & Handling	4	integer	Assuming 4 shift positions for the handling and storage of HBI or Pig iron (depending on which process pathway is selected) [31]
Shift position multiplier	4.8	worker/shift position	Used to estimate the number of people to staff each shift position [31]
Annual hours worked per worker	1920	(hrs/worker)/yr	Estimated based on a 40 hour week and 48 weeks per year
Average worker hourly wage	-	US$/hr	Refer to **Section 10**
Miscellaneous			
Electrical & Instrumentation Capital Costs	0.5584	-	Scale factor [51]
	8.76	tonne/year	Reference capacity [51]
	68,056	US$	Reference cost [51]
	97,233	A$	
Building & Storage Capital Costs	0.8	-	Scale factor [51]
	8.76	tonne/year	Reference capacity [51]
	6,160	US$	Reference cost [51]
	8,800	A$	
Other Miscellaneous Costs	0.8	-	Scale factor [51]
	8.76	tonne/year	Reference capacity [51]
	170,142	US$	Reference cost [51]
	243,060	A$	
Carbon Emissions Factors			
Grid Electricity Emissions	-	$kgCO_2eq/kWh$	Refer to **Section 9**
Natural Gas Emission	-	$kgCO_2eq/kWh$	Refer to **Section 9**
ESF Carbon Addition	-	$kgCO_2eq/tonne_{Coal}$	Refer to **Section 9**

1. Where applicable, dollar values have been adjusted to 2024 values. Values pertaining to plant or equipment costs were adjusted using CEPCI indices [13]. Costs pertaining to insurance, labour or personnel costs, were adjusted using a 3% annual CPI increase. Costs that were adjusted using a CPI increase have been stated above in the table.
2. Only required for the production of Hot-Briquetted Iron (HBI). The ironmaking pathway which uses an Electric Smelting Furnace (ESF) does not require HBI production.
3. The Electric Smelting Furnace (ESF) is used for pathways where iron ore cannot be beneficiated, so the gangue material can be removed in the ESF prior to the steelmaking step.

A schematic of the Ironmaking process for both the *Hematite* and *Magnetite Pathways* is provided below (**Figure S1** and **Figure S2**).

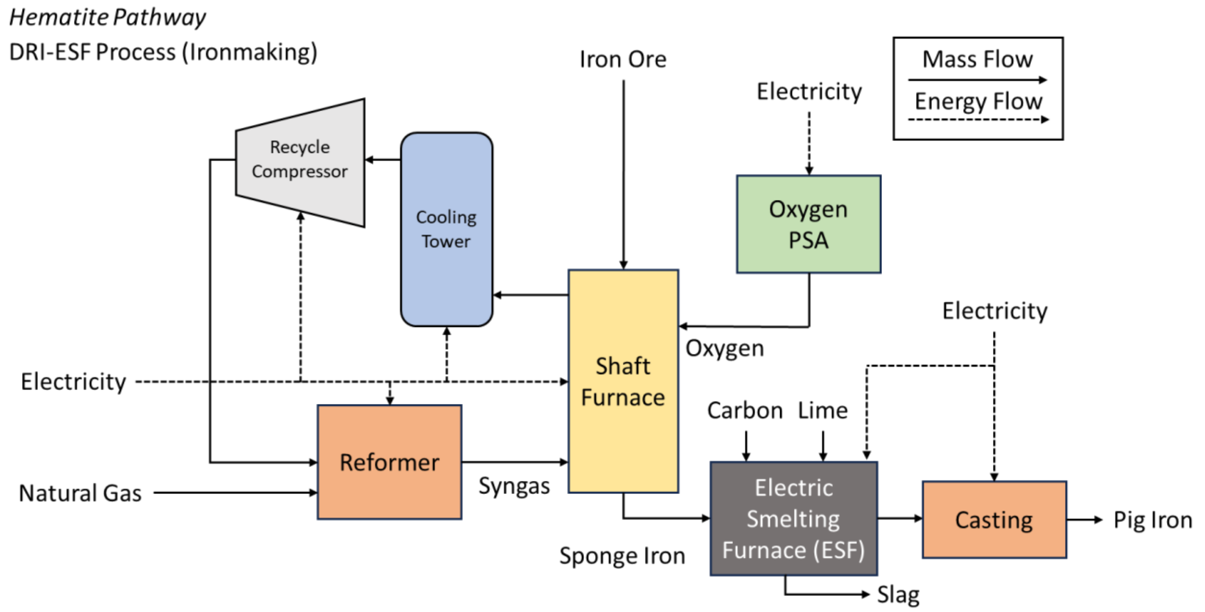


Figure S1. Process schematic for ironmaking in the *Hematite Pathway*

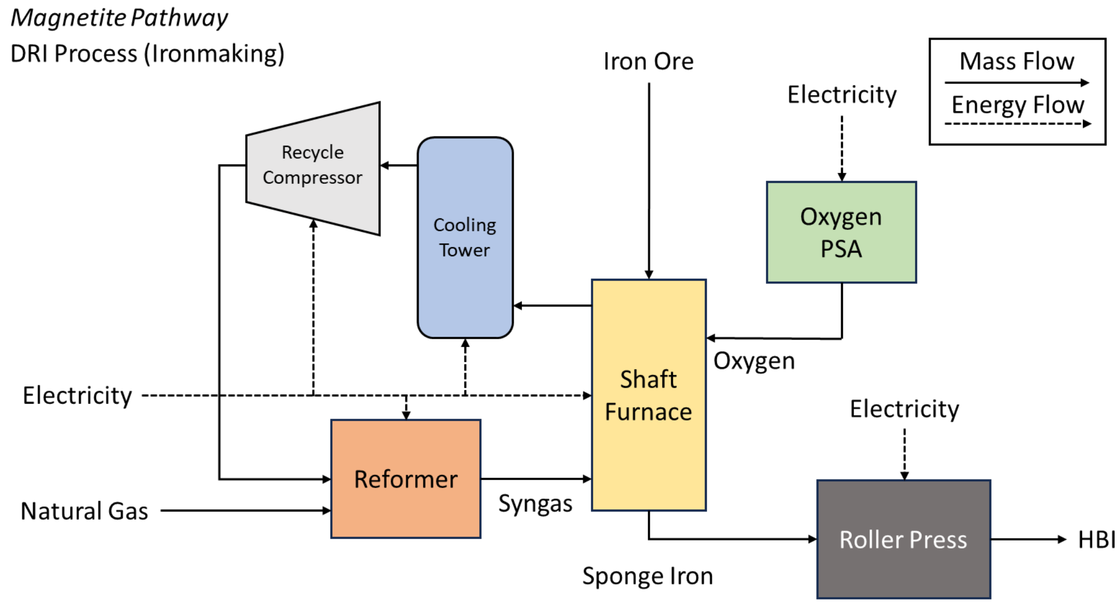


Figure S2. Process schematic for ironmaking in the *Magnetite Pathway*

6.2 Decarbonisation Assumptions

Two decarbonisation processes were considered for the ironmaking process. The first considered the use of synthetic natural gas, which can be used directly in the conventional DRI process. The second considered the use of hydrogen gas to replace natural gas as the reducing agent in the ironmaking process. The use of a steam methane reformer in the conventional natural gas-based DRI process is unnecessary if operating with a hydrogen-based DRI process. However, as the reaction of hydrogen with iron ore is endothermic, the hydrogen-based DRI process necessitates a hydrogen pre-heater, with heat assumed to be provided through the combustion of additional hydrogen [51].

The following **Table S13** outlines the assumptions used for model development. Compared to the base-case model, the hydrogen pre-heater replaces the reformer, and hydrogen gas replaces natural gas. All other model inputs are assumed to be equivalent.

Table S13. Model Assumptions for Hydrogen-based Ironmaking[1]

Ironmaking Cost Estimates			
Hydrogen Pre-heater			
Pre-heater sizing	0.25	MWh/tonne	Calculated based on energy requirements of hydrogen pre-heater [51]
Pre-heater capital cost	0.7848	-	Scale factor [51]
	1.0	MW	Reference capacity [51]
	223,082	US$	Reference cost [51]
	318,689	A$	
Annual maintenance cost	1.5	% CAPEX	Pre-heater annual maintenance cost, assumed equivalent to natural gas based DRI process [52]
Hydrogen requirements	0.062	tonne_{H2}/tonne	Calculated based on the stoichiometric requirement for iron ore reduction and heat of reaction of 99 kJ/mol [51]
Oxygen gas	55	kg/$\text{tonne}_{HotMetal}$	Oxygen requirements for DRI process [51]

1. Where applicable, dollar values have been adjusted to 2024 values using CEPCI indices [13]

7 Steelmaking Model

The steelmaking model was assumed to be operated as part of an integrated ironmaking and steelmaking facility.

7.1 Fossil Fuel Case Model Assumptions

Table S14. Integrated Steelmaking Model Parameters[1]

Financial Assumptions			
Discount Rate	7	%	Assumed
Economic Life	30	years	Based on prior project life of a green steel plant [51]
System Sizing			
Process plant design capacity ($Q_{Product}$)	-	$\text{tonne}_{\text{HotMetal}}$/year	Model input
Plant availability	90	%	Based on prior steel plant capacity factor [51]
Ironmaking Cost Estimates and Input Assumptions			
Shaft Furnace			
Shaft furnace sizing	-	$\text{tonne}_{\text{HotMetal}}$/year	Based on process plant design capacity ($Q_{Product}$) per annual hot metal production
Shaft furnace capital cost	0.6538	-	Scale factor [51]
	8.76	$\text{tonne}_{\text{HotMetal}}$/year	Reference capacity [51]
	47,841	US$	Reference cost [51]
	68,344	A$	
Annual maintenance cost	1.5	% CAPEX	Shaft furnace annual maintenance cost [52]
Electricity (DRI process)	70	kWh/$\text{tonne}_{\text{HotMetal}}$	Overall DRI process electricity requirements [53]
Iron ore	1.42-1.58	$\text{tonne}_{\text{Ore}}$/$\text{tonne}_{\text{HotMetal}}$	Calculated based on iron ore grade of 60-67% and metallic Fe content of the final product of 95%
Natural gas	0.20	$\text{tonne}_{\text{gas}}$/$\text{tonne}_{\text{HotMetal}}$	Natural gas requirements (0.17-0.23 $\text{tonne}_{\text{gas}}$/tonne) [51, 54]
Oxygen gas	3	kg/$\text{tonne}_{\text{HotMetal}}$	Oxygen requirements for DRI process [51]
Reformer			
Reformer sizing	0.71	MWh/$\text{tonne}_{\text{HotMetal}}$	Calculated based on energy requirements of syngas production [51]
Reformer capital cost	0.6505	-	Scale factor [51]
	1.0	MW	Reference capacity [51]
	4,806,408	US$	Reference cost [51]
	6,866,297	A$	
Annual maintenance cost	1.5	% CAPEX	Reformer annual maintenance cost [52]
Recycle Compressor			

Compressor sizing	0.023	$MWh/tonne_{HotMetal}$	Calculated based on energy requirements of recycle gas [51]
Compressor capital cost	0.7100	-	Scale factor [51]
	1.0	MW	Reference capacity [51]
	5,995,914	US$	Reference cost [51]
	8,565,591	A$	
Annual maintenance cost	1.5	% CAPEX	Compressor annual maintenance cost [52]
Cooling Tower			
Cooling tower sizing	1.0	$m^3/tonne_{HotMetal}$	Cooling water requirements (0.9-1.3 m^3/tonne) [51, 54]
Cooling tower capital costs	0.6303	-	Scale factor [51]
	8760	m^3/year	Reference capacity based on cooling water flowrate [51]
	59,277	US$	Reference cost [51]
	84,681	A$	
Annual maintenance cost	1.5	% CAPEX	Cooling tower annual maintenance cost [52]
Oxygen Pressure Swing Adsorption (PSA)			
Oxygen PSA sizing	-	$tonne_{O2}/tonne_{HotMetal}$	Determined by summing all unit process oxygen requirements
Oxygen PSA capital costs	0.6357	-	Scale factor [51]
	8.76	$tonne_{O2}$/year	Reference capacity [51]
	29,849	US$	Reference cost [51]
	42,641	A$	
Annual Maintenance Cost	2.5	% CAPEX	Oxygen PSA annual maintenance cost [55]
Electricity (Oxygen PSA)	385	$kWh/tonne_{O2}$	PSA oxygen generation electricity consumption [53]
Roller Press (Hot-Briquetted Iron Production)[2]			
Roller press sizing	-	$tonne_{HotMetal}$/year	Based on process plant design capacity ($Q_{Product}$) per annual hot metal production
Roller press capital costs	0.9	-	Scale factor, assumed.
	438,000	$tonne_{HBI}$/year	Capacity of HBI roller press [56]
	80,000	US$	Reference cost of HBI roller press [56]
	114,286	A$	
Annual maintenance cost	1.5	% CAPEX	Assumed similar to shaft furnace
Electricity (HBI production)	10	$kWh/tonne_{HBI}$	HBI briquette compression [10]
Electric Smelting Furnace (ESF)[3]			
ESF sizing	-	$tonne_{HotMetal}$/year	Based on process plant design capacity ($Q_{Product}$) per annual hot metal production
ESF capital costs	0.8	-	Scale factor. Assumed similar to an Electric Arc Furnace [55]
	4,920,000	tonne/yr	Reference capacity. Assumed similar to an Electric Arc Furnace [55]

	575,105,392	US$	Reference cost. Assumed similar to an Electric Arc Furnace [55]
	821,579,131	A$	
Annual maintenance cost	3	% CAPEX	Assumed similar to an Electric Arc Furnace annual maintenance cost (includes refractory lining) [57]
Slag production	0.20	$tonne_{Slag}/tonne_{HotMetal}$	Assumed similar to the slag production from an Electric Arc Furnace [52]
Electricity for ESF process	380	$kWh/tonne_{HotMetal}$	Electricity requirements, assumed similar to the operation of an EAF (355-380 kWh/tonne) if hot-linked, (453 kWh/tonne) if not hot-linked [51, 53]
Carbon addition for ESF process	0.027	$tonne_{C}/tonne_{HotMetal}$	Carbon addition for ESF operation. Assumed similar to Electric Arc Furnace [51]
Lime addition for ESF process	0.05	$tonne_{Lime}/tonne_{HotMetal}$	Lime addition for ESF operation. Assumed similar to Electric Arc Furnace (0.04-0.05 $tonne_{Lime}$/tonne) [51, 53]
Steelmaking Cost Estimates and Input Assumptions			
Electric Arc Furnace (EAF)[4]			
EAF Sizing	-	$tonne_{HotMetal}/year$	Based on process plant design capacity ($Q_{Product}$) per annual hot metal production
EAF capital costs	0.8	-	Scale factor [55]
	4,920,000	$tonne_{HotMetal}/yr$	Reference capacity [55]
	575,105,392	US$	Reference cost [55]
	821,579,131	A$	
Annual maintenance cost	3	% CAPEX	EAF annual maintenance cost (includes refractory lining) [57]
Slag production	0.20	$tonne/tonne_{HotMetal}$	Slag production from EAF [52]
Electricity for EAF process	380	$kWh/tonne_{HotMetal}$	Electricity requirements (355-380 kWh/tonne) if hot-linked, (453 kWh/tonne) if not hot-linked [51, 53]
EAF carbon addition	0.027	$tonne_{C}/tonne_{HotMetal}$	Carbon addition for EAF operation [51]
EAF lime addition	0.05	$tonne_{Lime}/tonne_{HotMetal}$	Lime addition for EAF operation 0.04-0.05 $tonne_{Lime}$/tonne [51, 53]
EAF oxygen gas requirements	0.054	$tonne_{O2}/tonne_{HotMetal}$	Oxygen gas addition for EAF operation [51]
EAF electrode replacement	2	$kg/tonne_{HotMetal}$	EAF electrode consumption rate [57]
Basic Oxygen Furnace (BOF)[5]			

BOF sizing	-	$tonne_{HotMetal}$/year	Based on process plant design capacity ($Q_{Product}$) per annual hot metal production
BOF capital costs	0.8	-	Scale factor [55]
	4,323,327	$tonne_{HotMetal}$/yr	Reference capacity [55]
	447,412,500	US$	Reference cost [55]
	639,160,714	A$	
Annual maintenance cost	5	% CAPEX	BOF annual maintenance cost [55]
Slag production	0.058	tonne/$tonne_{HotMetal}$	Slag production rate of 56-60 kg/$tonne_{HotMetal}$ [59, 60]
Electricity for BOF process	21	kWh/$tonne_{HotMetal}$	Electricity requirements of 20-23 kWh/$tonne_{HotMetal}$ [53, 61]
BOF lime addition	0.043	tonne/$tonne_{HotMetal}$	Lime addition for BOF operation [55]
BOF oxygen gas requirements	0.079	tonne/$tonne_{HotMetal}$	Oxygen requirements for BOF operation [61]
Continuous Casting			
Casting sizing	-	$tonne_{HotMetal}$/year	Based on process plant design capacity ($Q_{Product}$) per annual hot metal production
Casting capital costs	0.8	-	Scale factor. Based on continuous slab caster [55]
	4,000,000	tonne/yr	Reference capacity. Based on continuous slab caster [55]
	190,077,206	US$	Reference cost. Based on continuous slab caster [55]
	271,538,866	A$	
Annual maintenance cost	8	% CAPEX	Continuous casting annual maintenance cost [55]
Electricity (continuous casting)	10	kWh/$tonne_{HotMetal}$	Continuous casting electricity requirements [58]
Overall Process Input Costs			
Carbon cost	-	US$/tonne	Cost for carbon used for EAF addition. Refer to **Section 10**
Lime cost	-	US$/tonne	Cost for lime used for EAF addition. Refer to **Section 10**
Slag waste management	-	US$/tonne	Cost for slag waste management for ESF, EAF and BOF. Refer to **Section 10**
EAF electrode replacement cost	-	US$/$kg_{Electrode}$	Cost for EAF electrode replacement. Refer to **Section 10**
Operation and Labour Cost Estimates			
DRI process operation	4	integer	Assuming 4 shift positions for the operation of the DRI process [31]
ESF Process operation	4	integer	Assuming 4 shift positions for the operation of the ESF process [31]

EAF Process operation	4	integer	Assuming 4 shift positions for the operation of the EAF process [31]
BOF Process operation	4	integer	Assuming 4 shift positions for the operation of the BOF process [31]
Steel Storage & Handling	4	integer	Assuming 4 shift positions for the handling and storage of Steel [31]
Shift position multiplier	4.8	worker/shift position	Used to estimate the number of people to staff each shift position [31]
Annual hours worked per worker	1920	(hrs/worker)/yr	Estimated based on a 40 hour week and 48 weeks per year
Average worker hourly wage	-	US$/hr	Refer to **Section 10**
Miscellaneous			
Electrical & Instrumentation Capital Costs	0.5584	-	Scale factor [51]
	8.76	tonne/year	Reference capacity [51]
	68,056	US$	Reference cost [51]
	97,223	A$	
Building & Storage Capital Costs	0.8	-	Scale factor [51]
	8.76	tonne/year	Reference capacity [51]
	6,160	US$	Reference cost [51]
	8,800	A$	
Other Miscellaneous Costs	0.8	-	Scale factor [51]
	8.76	tonne/year	Reference capacity [51]
	170,142	US$	Reference cost [51]
	243,060	A$	
Carbon Emissions Factors			
Grid Electricity Emissions	-	$kgCO_2eq/kWh$	Refer to **Section 9**
Natural Gas Emissions	-	$kgCO_2eq/kWh$	Refer to **Section 9**
ESF and EAF Carbon Addition Emissions	-	$kgCO_2eq/tonne_{Coal}$	Refer to **Section 9**
EAF Electrode Consumption Emissions	-	$kgCO_2eq/tonne_{Electrode}$	Refer to **Section 9**

1. Where applicable, dollar values have been adjusted to 2024 values. Values pertaining to plant or equipment costs were adjusted using CEPCI indices [13]. Costs pertaining to insurance, labour or personnel costs, were adjusted using a 3% annual CPI increase. Costs that were adjusted using a CPI increase have been stated above in the table.
2. Only required for the production of Hot-Briquetted Iron (HBI). The ironmaking pathway which uses an Electric Smelting Furnace (ESF) does not require HBI production.
3. The Electric Smelting Furnace (ESF) is used for pathways where iron ore cannot be beneficiated, so the gangue material can be removed in the ESF prior to the steelmaking step.
4. The Electric Arc Furnace (EAF) is coupled with ironmaking processes that use a DRI process only, if feed ore grade permits, as outlined in **Report 2**.

5. The Basic Oxygen Furnace (BOF) is coupled with ironmaking processes that use an Electric Smelting Furnace (ESF), as outlined in **Report 2**.

A schematic of the integrated steelmaking process for both the *Hematite* and *Magnetite Pathways* is provided below (**Figure S3** and **Figure S4**).

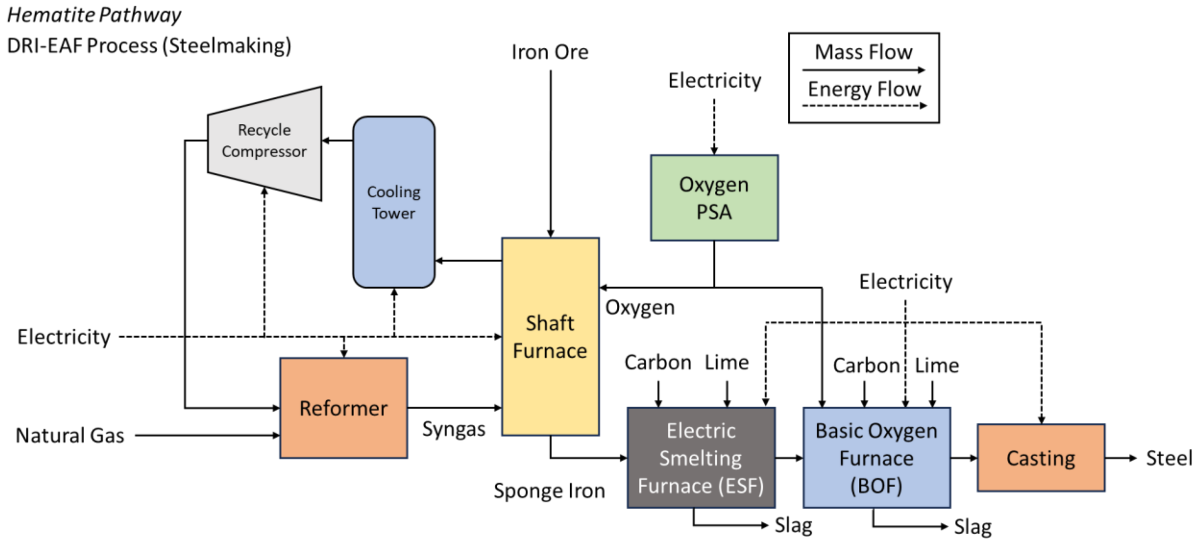


Figure S3. Process schematic for steelmaking in the *Hematite Pathway*

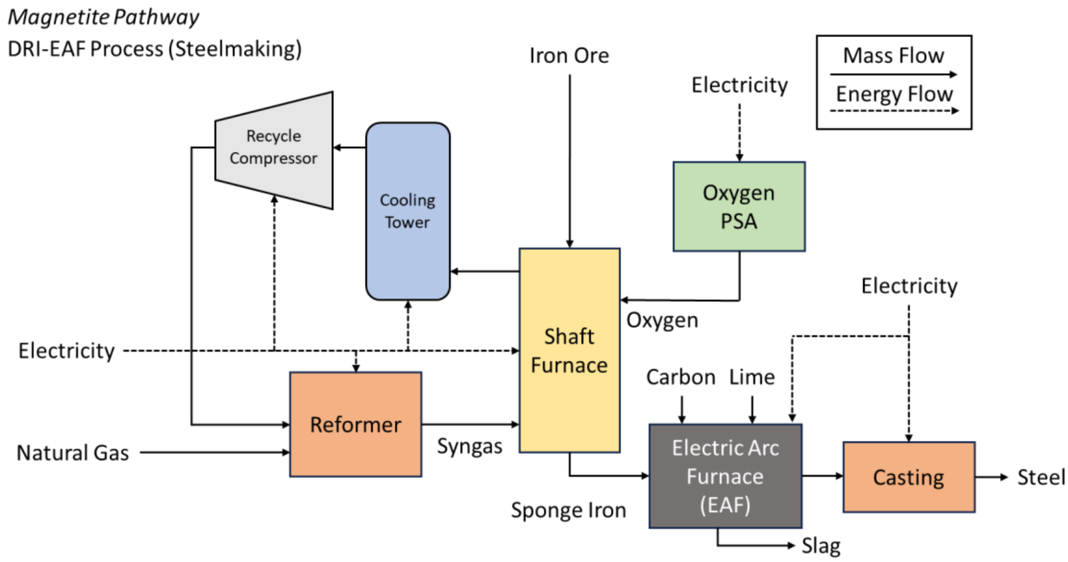


Figure S4. Process schematic for steelmaking in the *Magnetite Pathway*

7.2 Decarbonisation Assumptions

Two decarbonisation processes were considered for the ironmaking step of the integrated steelmaking process. The first considered the use of synthetic natural gas, which can be used directly in the conventional DRI process. The second considered the use of hydrogen gas to replace natural gas as the reducing agent in the ironmaking process. The use of a steam methane reformer in the conventional natural gas-based DRI process is unnecessary if operating with a hydrogen-based DRI process. However, as the reaction of hydrogen with iron ore is endothermic, the hydrogen-based DRI process necessitates a hydrogen pre-heater, with heat assumed to be provided through the combustion of additional hydrogen [51].

The following **Table S13** outlines the assumptions used for model development. Compared to the base-case model, the hydrogen pre-heater replaces the reformer, and hydrogen gas replaces natural gas. All other model inputs are assumed to be equivalent.

Table S15. Model Assumptions for Hydrogen-based Ironmaking[1]

Ironmaking Cost Estimates			
Hydrogen Pre-heater			
Pre-heater sizing	0.25	MWh/tonne	Calculated based on energy requirements of hydrogen pre-heater [51]
Pre-heater capital cost	0.7848	-	Scale factor [51]
	1.0	MW	Reference capacity [51]
	223,082	USD	Reference cost [51]
Annual maintenance cost	1.5	% CAPEX	Pre-heater annual maintenance cost, assumed equivalent to natural gas based DRI process [52]
Hydrogen requirements	0.062	$tonne_{H2}$/tonne	Calculated based on the stoichiometric requirement for iron ore reduction and heat of reaction of 99 kJ/mol [51]
Oxygen gas	55	$kg/tonne_{HotMetal}$	Oxygen requirements for DRI process [51]

1. Where applicable, dollar values have been adjusted to 2024 values using CEPCI indices [13]

8 Renewable Energy Generation Assumptions

The following assumptions were used for determining the levelised cost of renewable energy generation.

8.1 Renewable Electricity Generation

The following costs estimates (**Table S16**) were used to determine the cost to produce renewable electricity from solar PV and wind, relying on lithium-ion battery storage to firm supply.

Table S16. Renewable Electricity Generation Assumptions[1]

Parameter	Value	Unit	Notes
Financial Assumptions			
Discount Rate	7	%	Assumed
Economic Life	25	years	Based on IEA estimates [50]
Cost Assumptions			
Solar PV panel cost	1068	US$/kW	Based on current large-scale solar PV costs in Australia [16]. Solar PV lifespan assumed to be equal to project life.
	1526	A$/kW	
Solar PV OPEX	11.9	(US$/kW)/yr	Based on current large-scale solar PV costs in Australia [16]
	17	(A$/kW)/yr	
On-shore wind turbine cost	2127	US$/kW	Based on current on-shore wind costs in Australia [16]. Wind turbine lifespan assumed to be equal to project life.
	3038	A$/kW	
On-shore wind OPEX	17.5	(US$/kW)/yr	Based on current on-shore wind costs in Australia [16]
	25	(A$/kW)/yr	
Lithium battery storage cost	299	US$/kWh	Based on current 24h lithium-ion energy storage costs in Australia [16]. Battery operation costs are assumed to be included in solar PV and wind operation costs.
	427	A$/kWh	
Battery round-trip efficiency	85	%	Assumed
Battery lifespan	10	yr	Assumed.

1. Where applicable, dollar values have been adjusted to 2024 values using CEPCI indices [13]

8.2 Renewable Hydrogen Generation

The following costs estimates (**Table S17**) were used to determine the cost to produce green hydrogen via alkaline electrolysis powered by solar PV and wind. It was assumed that the hydrogen is compressed and stored at 200 bar pressure, prior to downstream use.

Table S17. Renewable Hydrogen Generation Assumptions[1]

Parameter	Value	Unit	Notes
Financial Assumptions			
Discount Rate	7	%	Assumed
Economic Life	25	years	Based on IEA estimates [50]

Cost Assumptions			
Electrolyser cost (Alkaline)	1343	US$/kW	Based on current alkaline electrolyser cost estimates [16]
	1919	A$/kW	
Electrolyser SEC	50.5	kWh/kg_{H2}	Based on Low Heat Value (LHV) efficiency of 66%, from IEA estimates [50]. Value aligns with current commercially available alkaline electrolyser [62]
Electrolyser Balance of Plant (BoP)	5.0	kWh/kg_{H2}	Energy required to operate balance of plant. Assumed based on the typical SEC of an alkaline electrolyser, accounting for electrolyser efficiency [62]
Electrolyser OPEX	3.0	% CAPEX	Based on IEA estimates [50]
Hydrogen Storage Duration	24	h	Assumed
Hydrogen Compressor Costs (200 bar)	97	US$/($kg_{H2}$/day)	Based on 200 bar hydrogen compressor [63]. Assumed operating costs are included in the electrolyser operating costs.
	139	A$/($kg_{H2}$/day)	
Hydrogen compressor SEC	3.0	kWh/kg_{H2}	Based on estimates for hydrogen compressor energy requirements [10]
Hydrogen Storage Cost (200 bar)	786	US$/($kg_{H2}$/day)	Based on 200 bar hydrogen storage [63] and peak hydrogen flow-rate. Assumed operating costs are included in the electrolyser operating costs.
	1,123	A$/($kg_{H2}$/day)	
Electrolyser Stack Life	10	yr	Based on an operating life of 90,000 hrs [64]
Electrolyser Stack Replacement Cost	20	% CAPEX	Based on electrolyser installed cost. Assumed.
Electrolyser Water Requirements	11	L/kg_{H2}	Typical alkaline electrolyser feedwater requirements [65]
Electrolyser Water Costs	-	USD/m^3	Refer to **Section 10**

1. Where applicable, dollar values have been adjusted to 2024 values using CEPCI indices [13]

8.3 Synthetic Natural Gas

The following parameters (**Table S18**) were used to estimate the cost of generating synthetic natural gas via the methanation reaction from syngas.

Table S18. Synthetic Natural Gas Generation Assumptions[1]

Parameter	Value	Unit	Notes
Financial Assumptions			
Discount Rate	7	%	Assumed
Economic Life	30	years	Based on IEA estimates [50]
Synthesis			

Capital cost	2,160	US$/kW$_{Fuel}$	Assumed costing similar to the Fischer-Tropsch process. Cost per kW of synthetic fuel [50]
	3,086	A$/kW$_{Fuel}$	
Annual operating costs	5	%	Percentage of CAPEX [50]
Electricity requirements	0.018	GJ/GJ$_{Fuel}$	Electricity requirements [50]
Hydrogen requirements	500	kg$_{H2}$/tonne$_{CH4}$	Stoichiometric requirements of Hydrogen
Carbon dioxide requirements	2750	kg$_{CO2}$/tonne$_{CH4}$	Stoichiometric requirements of CO_2
Carbon dioxide cost	30	US$/tonne	Cost of biogenic CO_2 [50]
	43	A$/tonne	
Liquefaction			
Capital cost	1,190	US$/(tonne$_{CH4}$/yr)	Capital cost 124-2,255 US$/tpa [66]
	1,700	A$/(tonne$_{CH4}$/yr)	
Annual operating costs	0.7	US$/GJ$_{CH4}$	Annual operating costs 0.69-4.10 US$/GJ$_{CH4}$ [66]
	1.0	A$/GJ$_{CH4}$	
Electricity requirements	0.07	GJ/GJ$_{CH4}$	Energy requirements 0.031-0.102GJ/GJ$_{CH4}$ [66]
Regassification			
Capital cost	50	US$/(tonne$_{CH4}$/yr)	Capital cost 50-450 US$/(tonne/yr) [67]
	71	A$/(tonne$_{CH4}$/yr)	
Annual operating cost	5	%	Assumed same as liquid hydrogen regasification
Natural gas for heat energy	1	%	Heat energy 1-2.5% of natural gas required to regassify [68]

1. Where applicable, dollar values have been adjusted to 2024 values using CEPCI indices [13]

8.4 Methanol

The following parameters (**Table S19**) were used to estimate the cost of generating methanol via the methanol synthesis reaction from syngas.

Table S19. Methanol Generation Assumptions[1]

Parameter	Value	Unit	Notes
Financial Assumptions			
Discount Rate	7	%	Assumed
Economic Life	30	years	Based on IEA estimates [50]
Synthesis			
Capital cost	2,160	US$/kW$_{Fuel}$	Assumed costing similar to the Fischer-Tropsch process. Cost per kW of synthetic fuel [50]
	3,086	A$/kW$_{Fuel}$	
Annual operating costs	5	%	Percentage of CAPEX [50]
Electricity requirements	0.018	GJ/GJ$_{Fuel}$	Electricity requirements [50]
Hydrogen requirements	187.5	kg$_{H2}$/tonne$_{CH4}$	Stoichiometric requirements of Hydrogen

Carbon dioxide requirements	1,375	$kg_{CO2}/tonne_{CH4}$	Stoichiometric requirements of CO_2
Carbon dioxide cost	30	US$/tonne	Cost of biogenic CO_2 [50]
	43	A$/tonne	

1. Where applicable, dollar values have been adjusted to 2024 values using CEPCI indices [13]

8.5 Ammonia

The following parameters (**Table S20**) were used to estimate the cost of generating ammonia via the Haber-Bosch reaction.

Table S20. Ammonia Generation Assumptions[1]

Parameter	Value	Unit	Notes
Financial Assumptions			
Discount Rate	7	%	Assumed
Economic Life	30	years	Based on IEA estimates [50]
Synthesis			
Capital cost	770	$US\$/(tonne_{NH3}/yr)$	Cost per tonne of ammonia. Includes air separation [50]
	1,100	$A\$/(tonne_{NH3}/yr)$	
Annual operating costs	3	%	Percentage of CAPEX [50]
Electricity requirements	2.2	$GJ/tonne_{NH3}$	Electricity requirements [50]
Hydrogen requirements	177	$kg_{H2}/tonne_{NH3}$	Stoichiometric requirements of Hydrogen
Ammonia-cracking			
Capital cost	3,050	$US\$/(tonne_{NH3}/yr)$	Capital cost [50]
	4,357	$A\$/(tonne_{NH3}/yr)$	
Annual operating cost	4	%	Percentage of CAPEX [50]
Electricity requirements	1.5	kWh/kg_{H2}	Electricity consumption [50]
Heat energy requirements	9.7	kWh/kg_{H2}	Heat energy assumed to be delivered from hydrogen [50]
Dehydrogenation rate	99	%	Dehydrogenation rate [50]
PSA hydrogen recovery rate	99	%	Pressure Swing Adsorption (PSA) recovery rate (used to separate hydrogen stream) [50]

1. Where applicable, dollar values have been adjusted to 2024 values using CEPCI indices [13]

8.6 Liquefied Hydrogen

The following parameters (**Table S18**) were used to estimate the cost of generating liquefied hydrogen.

Table S21. Liquefied Hydrogen Generation Assumptions[1]

Parameter	Value	Unit	Notes
Financial Assumptions			
Discount Rate	7	%	Assumed
Economic Life	30	years	Based on IEA estimates [50]
Liquefaction			
Capital cost	5,900	US$/(tonne$_{H2}$/yr)	Capital cost 4,102-7,700 US$/tpa [69]
	8,429	A$/(tonne$_{H2}$/yr)	
Annual operating costs	3	%	Percentage of CAPEX 2-4% [69]
Electricity requirements	6.0	kWh/kg$_{H2}$	Electricity requirements [50]
Regassification			
Capital cost	425	US$/(tonne$_{H2}$/yr)	Capital cost 112-432 US$/kW$_{H2}$ (425-1642 US$/(tonne$_{H2}$/yr) [70]
	607	A$/(tonne$_{H2}$/yr)	
Annual operating cost	5	%	Based on an OPEX of 1 US$/(tonne$_{H2}$/day) for a stated CAPEX of 20 US$/(tonne$_{H2}$/day) [50]
Energy requirements	0.5	kWh/kg$_{H2}$	Specific energy requirements 0.01-0.005 kWh/kWh$_{H2}$ (0.333-0.1665 kWh/kg$_{H2}$) [70] Assumed energy is provided by electricity

1. Where applicable, dollar values have been adjusted to 2024 values using CEPCI indices [13]

8.7 Liquid Organic Hydrogen Carrier

The following parameters (**Table S22**) were used to estimate the cost of using a liquid organic hydrogen carrier (LOHC) for transporting hydrogen. The following assumptions are based on the use of toluene - methylcyclohexane (MCH) as the hydrogen carrier [50].

Table S22. LOHC Assumptions[1]

Parameter	Value	Unit	Notes
Financial Assumptions			
Discount Rate	7	%	Assumed
Economic Life	30	years	Based on IEA estimates [50]
Synthesis			
Capital cost	790	US$/(tonne$_{H2}$/yr)	Capital costs [50]
	1,129	A$/(tonne$_{H2}$/yr)	
Annual operating costs	4	%	Percentage of CAPEX [50]
Electricity requirements	1.5	kWh/kg$_{H2}$	Electricity requirements [50]

Reconversion			
Capital cost	2,950	US$/(tonne$_{H2}$/yr)	Capital costs [50]
	4,214	A$/(tonne$_{H2}$/yr)	
Annual operating cost	4	%	Percentage of CAPEX [50]
Electricity requirements	1.5	kWh/kg$_{H2}$	Electricity requirements [50]
Heat energy requirements	13.6	kWh/kg$_{H2}$	Thermal energy requirements [50]. Assumed to be provided by hydrogen
Dehydrogenation rate	98	%	Dehydrogenation rate [50]
PSA hydrogen recovery rate	99	%	Pressure Swing Adsorption (PSA) recovery rate (used to separate hydrogen stream) [50]

1. Where applicable, dollar values have been adjusted to 2024 values using CEPCI indices [13]

9 Emissions Factors Assumptions

The following **Table S23** outlines the emissions factors assumed for the analysis.

Table S23. Emissions factors used in analysis

Parameter	Value	Units	Notes and Assumptions
Diesel Fuel Emissions	0.253	$kgCO_2eq/kWh$	Calculated based on an emissions intensity of 70.4 $kgCO_2eq/GJ$ for diesel use in heavy-duty vehicles [71]
Natural Gas Emissions	0.186	$kgCO_2eq/kWh$	Calculated based on an emissions intensity of 51.5 $kgCO_2eq/GJ$ for natural gas distributed in a pipeline [71]
Explosive Emissions	1.40	$kgCO_2eq/kg_{ANFO}$	Assuming the use of Ammonium Nitrate Fuel Oil (ANFO). Based on an emissions factor of 0.7 $kgCO_2eq/tonne_{ore}$ [8] and an explosives consumption rate of 0.5 $kg/tonne_{Ore}$ [8]
Electric Smelting Furnace (ESF) Carbon Addition Emissions	2.62	$kgCO_2eq/kg_{Coal}$	Assuming addition of anthracite coal, emissions calculated as its stationary combustion as fuel [71]
Electric Arc Furnace (EAF) Carbon Addition Emissions	2.62	$kgCO_2eq/kg_{Coal}$	Assuming addition of anthracite coal, emissions calculated as its stationary combustion as fuel [71]
Electric Arc Furnace (EAF) Graphite Electrode Consumption Emissions	2.62	$kgCO_2eq/kg_{Electrode}$	Assuming graphite has similar emissions to anthracite coal, emissions calculated as its stationary combustion as fuel [71]
Heavy Fuel Oil Emissions	2.98	$kgCO_2eq/kg_{Fuel}$	Calculated based on an emissions intensity of Fuel Oil of 73.84 $kgCO_2eq/GJ$ [71] and an energy content of 40.4 MJ/kg [39]
Grid Electricity Emissions	0.660	$kgCO_2eq/kWh$	New South Wales [71]
	0.770	$kgCO_2eq/kWh$	Victoria [71]
	0.710	$kgCO_2eq/kWh$	Queensland [71]
	0.230	$kgCO_2eq/kWh$	South Australia [71]
	0.510	$kgCO_2eq/kWh$	Western Australia – South West Interconnected System (SWIS) [71]
	0.610	$kgCO_2eq/kWh$	Western Australia – North West Interconnected System (NWIS) [71]
	0.150	$kgCO_2eq/kWh$	Tasmania [71]
	0.630	$kgCO_2eq/kWh$	National Average [71]
Renewable Electricity Emissions	0	$kgCO_2eq/kWh$	See footnote[1]
Renewable Hydrogen Emissions	0	$kgCO_2eq/kWh$	See footnote[2]
Synthetic Natural Gas Emissions	0.001	$kgCO_2eq/kWh$	See footnote[3]
Renewable Ammonia Emissions	0.008	$kgCO_2eq/kg_{Fuel}$	See footnote[4]
Renewable Methanol Emissions	0.003	$kgCO_2eq/kg_{Fuel}$	See footnote[5]

1. Although the production of solar PV panels and wind turbines incur some scope 3 emissions [72], scope 3 emissions were not considered in this analysis.
2. Although the production of electrolysers incur some scope 3 emissions [73], scope 3 emissions were not considered in this analysis. Furthermore, although there is some literature emerging on the global warming potential (GWP) of hydrogen, there is still much uncertainty surrounding these values [74], hence the scope 1 emissions from hydrogen use were assumed to be negligible.
3. The carbon dioxide (CO_2) emissions from synthetic natural gas are assumed to be carbon neutral. However, the use of natural gas still results on the release of methane (CH_4) and nitrous oxide (N_2O). Accounting for these emissions results in an emissions factor of 0.13kgCO_2eq/GJ [71].
4. The combustion of ammonia results in the release of nitrogen oxides (NO_x), nitrous oxide (N_2O), and ammonia (NH_3). However, these emissions are mostly removed from the exhaust through selective catalytic reduction (SCR) and scrubbing [75]. Of these, the DCCEEW national greenhouse gas accounts factors account for the GWP of N_2O [71]. Accounting for N_2O emissions from ammonia combustion after SCR and scrubbing results in an emissions factor of between 0.004-0.012 kgCO_2eq/kg [75].
5. The CO_2 emissions from renewable methanol are assumed to be carbon neutral. However, the combustion of methanol results in the release of carbon monoxide (CO), methane (CH_4) and nitrogen oxides (NO_x) [76]. Of these, the DCCEEW national greenhouse gas accounts factors account for the GWP of CH_4 [71]. Accounting for CH_4 emissions from methanol combustion results in an emissions factor of 0.003 kgCO_2eq/kg.

10 Cost Inputs and Assumptions

The following **Table S24** outlines the cost inputs and assumptions that were not regio-specific.

For an overview of cost inputs and assumptions that were regio-specific, refer to **Section 3.9** in **Report 3**.

Table S24.Consumables Cost Inputs and Assumptions

Input Costs	Value	Units	Notes and Assumptions
Explosives	2,059	US$/tonne$_{ANFO}$	Cost of Ammonium Nitrate Fuel Oil (ANFO) [77]
	2,942	A$/tonne$_{ANFO}$	
Diesel fuel	0.138	US$/kWh	Average cost of diesel in Australia of 1.37 US$/L [78], converted using a mass and energy density of 0.836 kg/L and 42.8 MJ/kg [79]
	0.197	A$/kWh	
Heavy Fuel Oil (HFO)	650	US$/tonne	Based on a global average bunker price of Very Low Sulphur Fuel Oil (VLSFO)
	928	A$/tonne	
Carbon	170	US$/tonne	Cost for carbon used for ESF or EAF addition. Based on the price of coking coal [80]
	243	A$/tonne	
Lime	80	US$/tonne	Cost for lime used for EAF, EAF or BOF addition [81]
	114	A$/tonne	
Slag waste management	30	US$/tonne	Cost for slag waste management for ESF, EAF or BOF [51]
	43	A$/tonne	
EAF electrode replacement	4	US$/kg$_{Electrode}$	Cost for EAF electrode replacement 4 EUR/kg$_{Electrode}$ [57]
	5.7	A$/kg$_{Electrode}$	
Electrolyser water cost	5	US$/m^3	Cost of water for green hydrogen production. Value is an over-estimate of desalinated water costs of 2.5 US$/m^3 [82] to account for any challenges in accessing water.
	7.1	A$/m^3	
Grid electricity cost (Germany)	0.30	US$/kWh	Based on European electricity prices [83] Grid electricity prices used for the reconversion of hydrogen derivates at the Port of Hamburg
	0.43	A$/kWh	

11 Renewable Energy Generation Cost Estimates

11.1 Renewable Energy and Green Hydrogen Generation Cost Estimates

The following **Figure S5** outlines the costs and optimisation outputs for each location. Hydrogen results are for **alkaline electrolysis**.

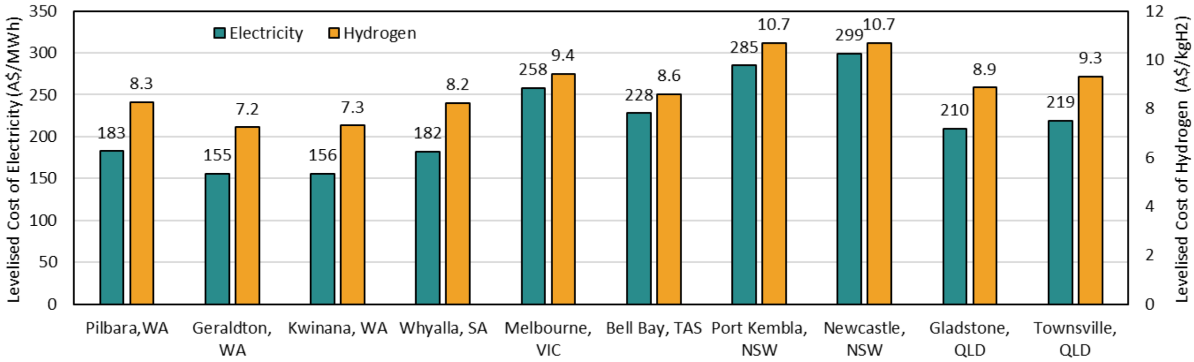


Figure S5. Renewable electricity and hydrogen generation cost estimates

The following **Table S25** and **Table S26** outline the optimisation results for renewable electricity and renewable hydrogen generation.

Table S25. Optimisation results for renewable electricity generation from solar PV and wind

Location	Solar Overcapacity (factor)	Wind Overcapacity (factor)	Battery Storage Duration (h)	System Capacity Factor (%)
Pilbara, WA	2.5	3.0	2	90.43
Geraldton, WA	2.0	2.5	2	90.36
Kwinana, WA	2.0	2.5	2	90.25
Whyalla, SA	2.5	3.0	2	90.69
Melbourne, VIC	3.0	2.5	8	90.28
Bell Bay, TAS	2.5	3.5	4	90.63
Port Kembla, NSW	3.5	3.0	8	90.35
Newcastle, NSW	3.5	3.5	8	91.5
Gladstone, QLD	2.5	3.0	4	90.7
Townsville, QLD	3.0	3.0	4	90.59

Table S26. Optimisation results for renewable hydrogen generation from solar PV and wind

Location	Solar Overcapacity (factor)	Wind Overcapacity (factor)	Battery Storage Duration (h)	System Capacity Factor (%)
Pilbara, WA	1.0	1.5	0	66.6
Geraldton, WA	1.0	1.0	0	69.11
Kwinana, WA	1.0	1.0	0	68.3
Whyalla, SA	1.0	1.0	0	66.91
Melbourne, VIC	1.0	1.5	0	58.41
Bell Bay, TAS	1.0	1.0	0	52.82
Port Kembla, NSW	1.5	0.5	0	46.75
Newcastle, NSW	2.0	0.0	0	33.72
Gladstone, QLD	1.0	1.5	0	62.07
Townsville, QLD	1.0	1.5	0	59.07

11.2 PEM vs Alkaline Electrolyser Cost Estimates

For reference, the cost of producing hydrogen from proton exchange membrane (PEM) is provided below (**Figure S6**). This assumes a capital cost of **3,141 A$/kW**, compared to a cost of **1,919 A$/kW** for alkaline electrolysers [16], resulting in a 15-23% increase in hydrogen production costs across the locations analysed.

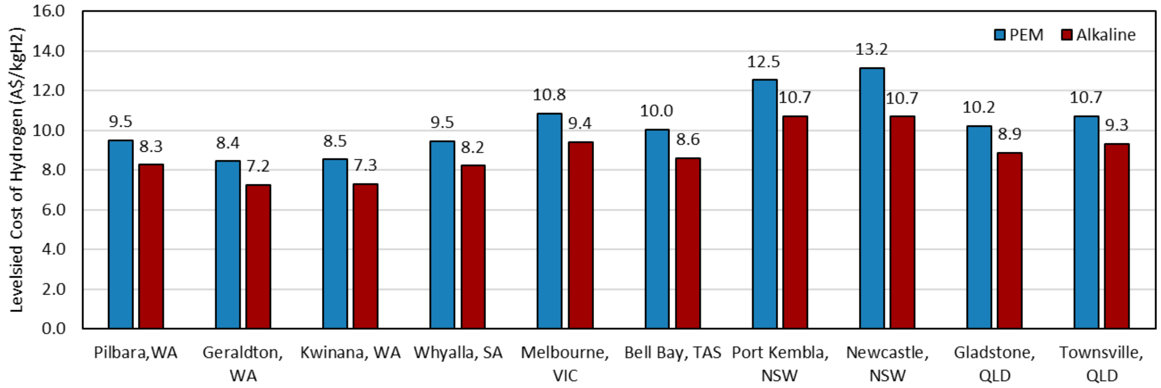


Figure S6. Cost to produce hydrogen from PEM vs Alkaline electrolysis

11.3 Synthetic Natural Gas, Methanol and Ammonia Cost Estimates

Results for hydrogen derivatives used for domestic applications, which includes synthetic natural gas for local iron and steelmaking, and ammonia and methanol as low carbon maritime fuels are provided in the following **Table S27**.

These results are based on the generation assumptions in **Section 8**, where renewable electricity and green hydrogen generation results for each location were used to determine hydrogen derivatives cost for each location.

Table S27. Synthetic Natural Gas, Methanol and Ammonia Costs

Location	Methanol (A$/tonne)	Ammonia (A$/tonne)	Synthetic Natural Gas (A$/kWh)
Pilbara, WA	1910	1709	0.360
Geraldton, WA	1715	1511	0.323
Kwinana, WA	1728	1524	0.325
Whyallah, SA	1901	1701	0.358
Melbourne, VIC	2133	1959	0.403
Bell Bay, TAS	1976	1795	0.373
Port Kembla, NSW	2377	2203	0.450
Newcastle, NSW	2376	2209	0.449
Gladstone, QLD	2025	1832	0.382
Townsville, QLD	2109	1917	0.398
Average-Case	2025		

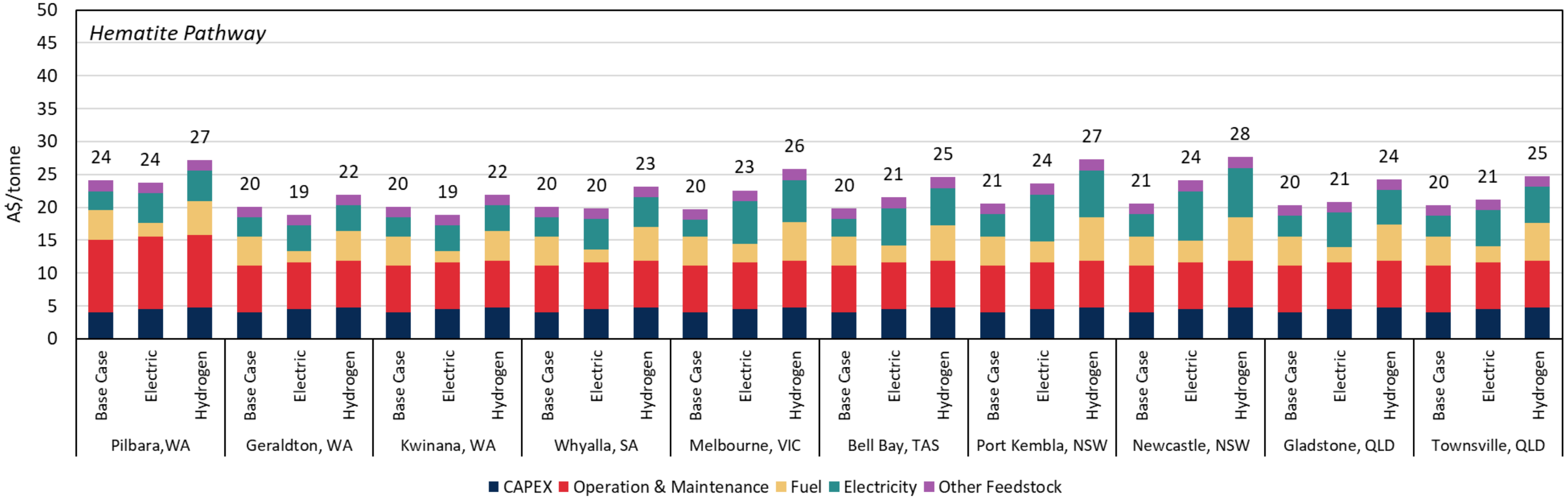
Methanol *average-case* results refer to the methanol cost used to generate **Figure 17**, **Section 5.2** in the report, based on the *average-case* hydrogen and electricity costs provided in **Table 4**, **Section 3.9** of the report.

12 Cost Estimates for Value Chain Decarbonisation Options

The following section (**Section 12.1-12.5**) provide cost comparisons between each of the decarbonisation options considered for each aspect of a green iron and steel value chain between Australia and Germany. In each instance, the decarbonisation option was compared to conventional fossil fuel-based production, referred to as the *Base Case*. Details of the decarbonisation options are provided in **Section 5** of **Report 3.**

Based on current costs, battery electric locomotives (for locations without existing catenary lines) were the only decarbonisation option that showed overall operational savings compared to fossil fuel-based alternatives across all locations (**Figure S10, Section 12.4**). These savings remained even when accounting for the higher electricity costs of renewable energy firmed by lithium-ion batteries. Similarly, the use of renewable electricity for ore extraction & processing demonstrated cost savings, but only for the *Hematite Pathway* in Geraldton, WA and Kwinana, WA where the estimated cost of renewable electricity was sufficiently low (**Figure S7, Section 12.1**).

12.1 Iron Ore Extraction & Processing



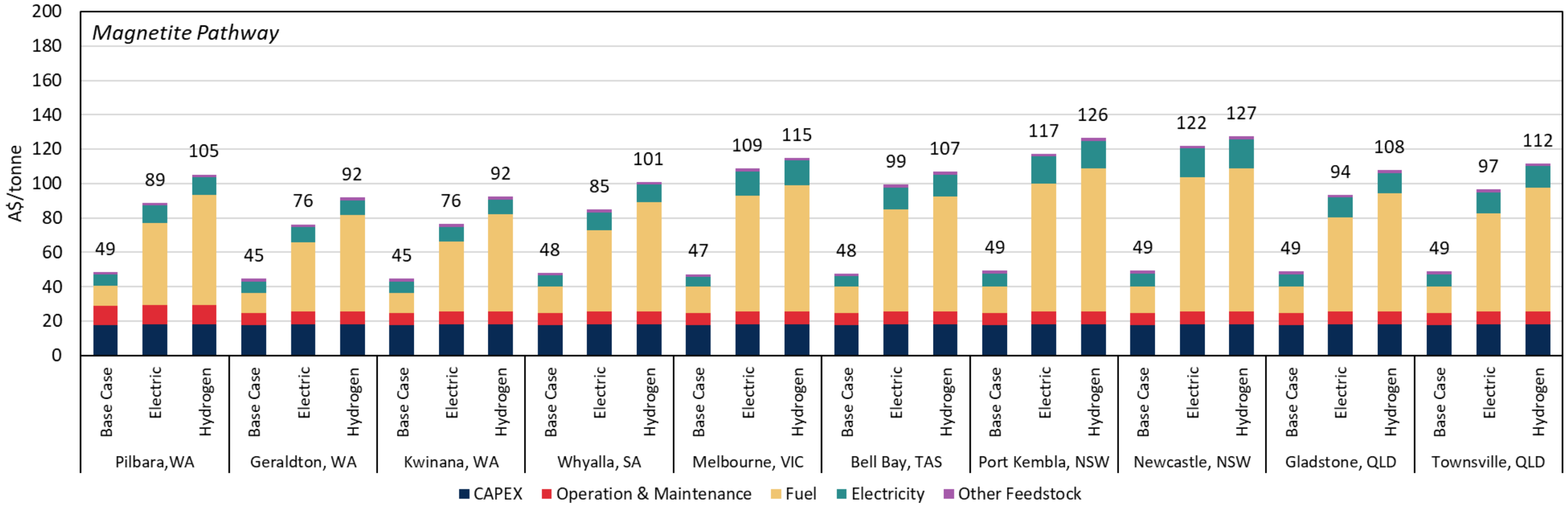


Figure S7. Iron ore extraction & processing fossil fuel (base case) vs decarbonisation options. Analysis based on a mine site capacity of 5Mtpa

12.2 Ironmaking

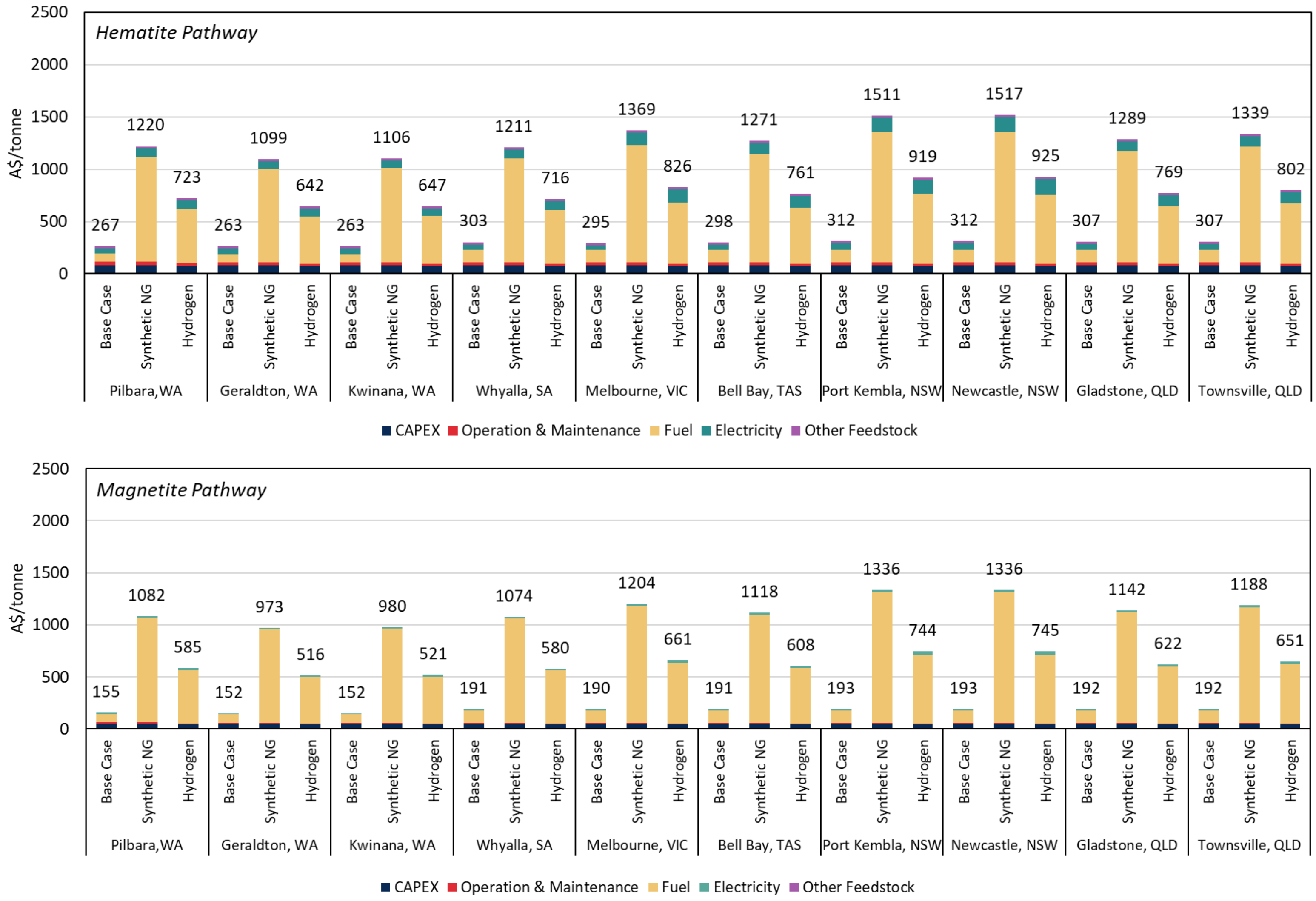


Figure S8. Ironmaking fossil fuel (base case) vs decarbonisation options. Analysis based on a production capacity of 1Mtpa

12.3 Steelmaking

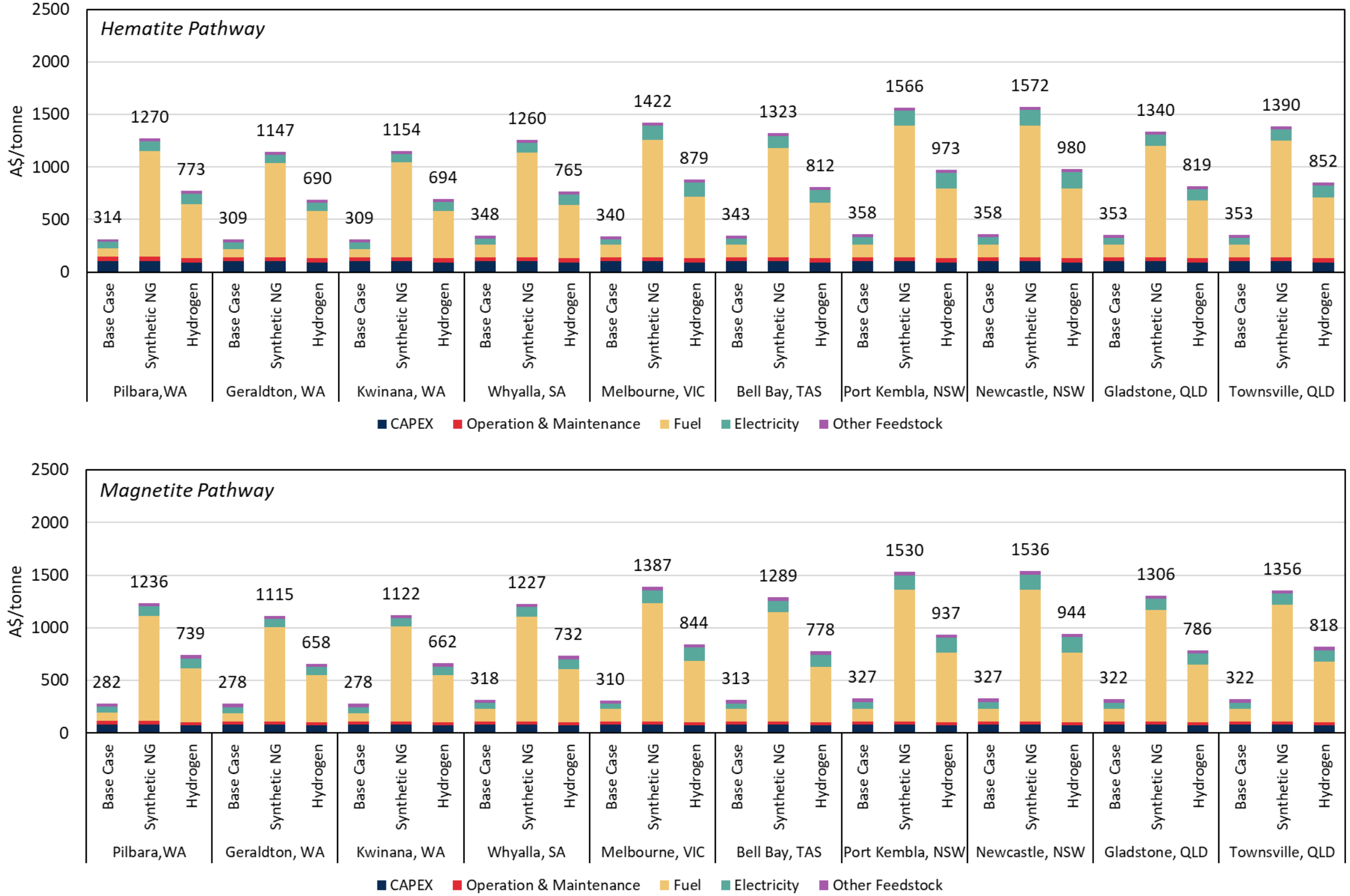


Figure S9. Steelmaking fossil fuel (base case) vs decarbonisation options. Analysis based on a production capacity of 1Mtpa. Processes operated as integrated steel mills.

12.4 Rail Transport

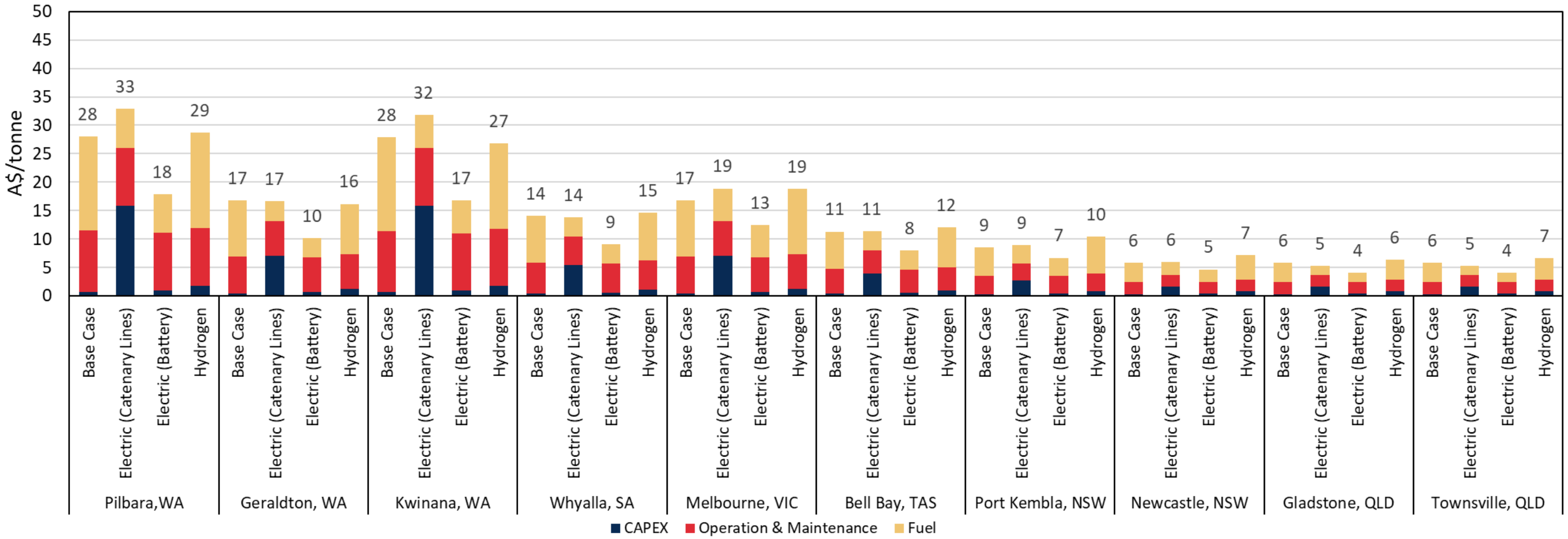


Figure S10. Rail transport fossil fuel (base case) vs decarbonisation options. Analysis assumed rail operations deliver maximum deliverable volumes per annum

12.5 Shipping

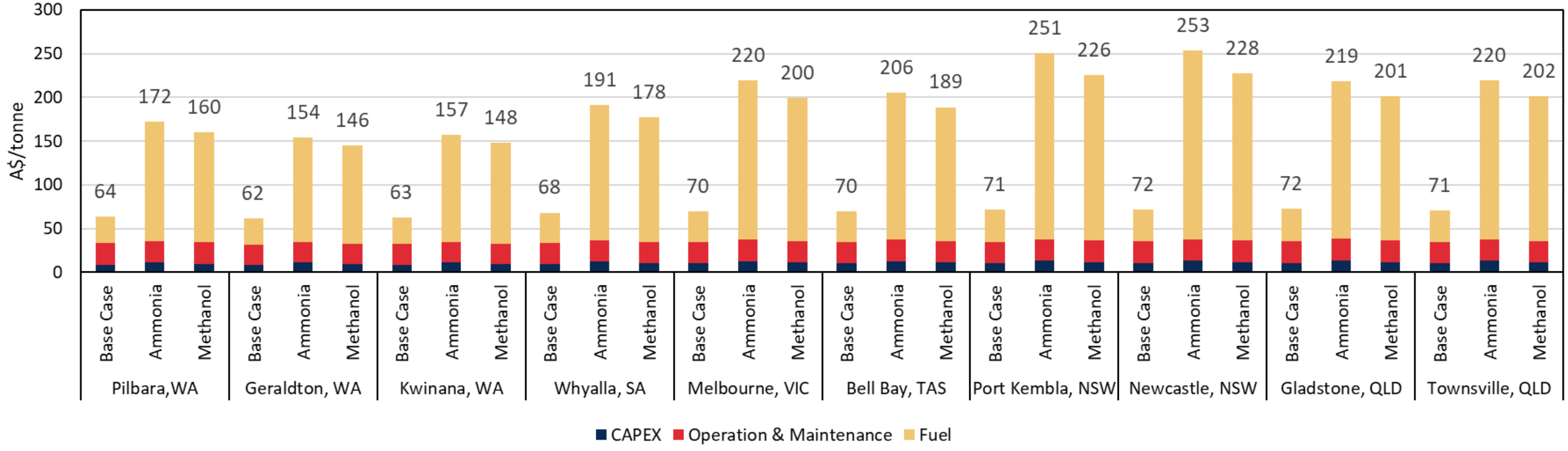


Figure S11. Dry bulk shipping fossil fuel (base case) vs decarbonisation options. Analysis assumed rail operations deliver maximum deliverable volumes per annum

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