South Australian Green Iron Supply Chain Study

Modelling Green Iron Production with Renewable Hydrogen and Magnetite Iron Ore in South Australia

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Abstract

This document presents the final report for the Monash-DEM project, "South Australian Green Iron Supply Chain Study" (Ref: SR336). The study investigates the feasibility of producing green iron in South Australia by leveraging the state's abundant renewable energy resources and magnetite iron ore reserves. It specifically models integrated systems of wind, solar PV, and energy storage for the production of hydrogen-based green iron. Preliminary techno-economic modelling suggests that a vertically integrated approach — encompassing mining, renewable electricity generation, hydrogen production, and iron downstream processing — could significantly reduce costs relative to more segmented supply chains. For example, a disaggregated 2.5 million tonnes per annum supply chain, where each operation in the supply chain is designed and managed independently, operating at full capacity could incur production costs up to $862 per tonne. In comparison, an integrated system could lower costs to $678 per tonne. With government support, such as low-interest loans, these costs could potentially be reduced to $500-600 per tonne by 2030. Nevertheless, further research is necessary to confirm these findings conclusively. Additional geological surveys, alternative technology and critical infrastructure assessments, supply chain comparisons, and policy evaluations are recommended to build upon this preliminary analysis. By strategically developing its magnetite ores and renewable energy, South Australia has the potential to produce cost-competitive green iron and metals for domestic markets and international exports.

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Contents

1. Introduction

With the steel industry responsible for 8% of global energy demand and 7% of all energy-related carbon emissions [1], there is a pressing need to reduce the climate impact of this important industry. Green iron and steel could hold the solution to the twin challenges of decarbonizing the global steel industry and finding an international market for Australian hydrogen.

Leveraging its world-leading renewable and magnetite resources, South Australia has a strategic opportunity to establish globally competitive green metals industries. This report, commissioned by the Department for Energy and Mining (DEM) of the South Australian State Government, analyses the economic feasibility of green iron production, capitalising on the state's abundant wind and solar resources.

This analysis focuses specifically on modelling hot briquetted iron (HBI) production scenarios in South Australia across projected costs, plant configurations, and temporal renewable energy availability. This study aims to support a broader effort by the Port of Rotterdam (PoR) and DEM to evaluate export value chain options from South Australia and compare the economics of using locally produced HBI in the EU to importing HBI from South Australia for European steelmakers.

Three scenarios are evaluated, associated with the following value chains established by 2030:

- **500ktpa vertically integrated HBI demonstration plant**
- **2.5mtpa vertically integrated HBI commercial plant**
- **2.5mtpa disaggregated (i.e., non-vertically integrated model) HBI commercial plant**

Both the integrated and disaggregated models are designed to ensure **constant and continuous** hydrogen inflow/offtake to support steady-state iron production needs.

A vertically integrated production model allows a single entity to control all stages of the green iron value chain, from renewable energy and hydrogen supply to final iron production. This integrated approach, as proposed in the 500ktpa and main 2.5mtpa scenarios, enables holistic system design and streamlined operations for enhanced efficiency and cost savings. For example, storage solutions and plant capacities can be optimally sized to manage variability from renewable electricity generation.

In contrast, the alternative 2.5mtpa scenario entails a disaggregated structure where each supply chain stage is independently designed and managed. The separation of electricity supply, hydrogen production, and iron processing into separate entities can lead to higher overall costs and reduced system efficiency.

This report examines the economic factors and system requirements at each stage of the green iron supply chain under evaluation. Specifically, it will identify opportunities for design optimisation across the prospective stages of iron ore extraction, iron ore processing, green hydrogen production, and final HBI output, as well as provide the associated production cost estimates.

2. Location

Leveraging existing infrastructure will be key to developing green metal hubs. Analysis by Monash and Geoscience Australia [2, 3] found a synergy between potential hydrogen hubs and future iron ore operations (Figure 1). Because of the supporting infrastructure, Eyre Peninsula (SA), with its substantial iron ore resources, is highly prospective for magnetite mining, renewable energy development and subsequent hydrogen production [2].

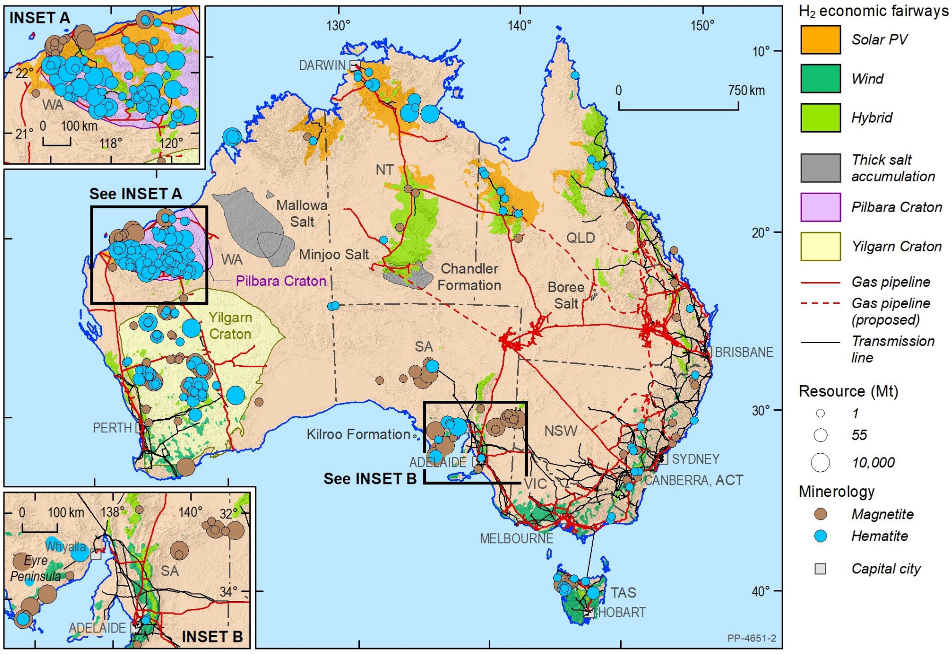

Figure 1: Critical infrastructure map overlain with annual average solar capacity factor for Australia taken from Wang et al. [2]. It illustrates that the resource is broadly distributed, but differences in local infrastructure lead to variations in economic potential. The shaded areas show high potential regions for producing farm-gate and off-grid hydrogen from solar, wind, and hybrid sources and locations of iron ore deposits (the coloured dots) in Australia. Deposit locations are based on Britt et al. [4], and the size of the symbol reflects the deposit size category. INSET A shows expanded views of the Pilbara region of Western Australia, and INSET B shows the Eyre Peninsula in South Australia.

Following initial consultations with DEM, the Eastern Eyre Peninsula was chosen as the primary area for this preliminary analysis. Recognized as Renewable Energy Zone S8 in the Australian Energy Market Operator (AEMO)'s 2022 Integrated System Plan (ISP) [5], as illustrated in Figure 2, this region was selected due to its strategic proximity to port infrastructure and the potential for developing new deep-water port facilities. The zone's proximity to existing mining activities in Whyalla and iron ore deposits also makes it well-positioned to support green metals manufacturing powered by the region's abundant and complementary wind and solar resources.

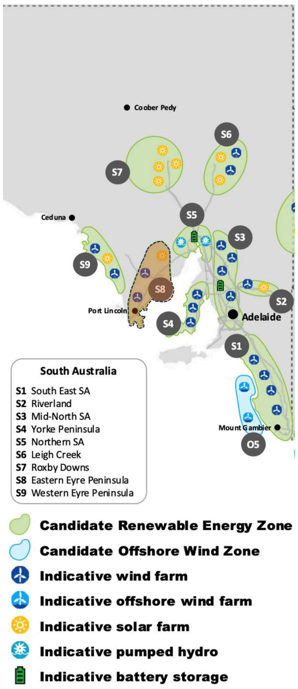

Figure 2: South Australia Renewable Energy Zones [5].

3. Renewable Resources

Robust projections of renewable energy availability are critical inputs for techno-economic modelling. To incorporate high-quality temporal generation profiles, this analysis utilises average half-hourly capacity factors across the year for the East Eyre Peninsula published in the AEMO's 2022 ISP [5].

The ISP provides an authoritative data source, given AEMO's central role in national electricity market infrastructure planning. Their projections are underpinned by extensive modelling and weather analysis tailored to each region. Leveraging the granular capacity factors from AEMO's ISP aligns the assumptions with Australia's broader strategic infrastructure development plans.

The complementary nature of wind and solar power is evident on the east Eyre Peninsula. Figure 3 shows the hourly availability factors for wind and solar resources across the year 2019. While solar power relies on sunlight and, therefore, peaks during the day, wind power can offer more consistent energy generation throughout the day and year. This is especially beneficial during nighttime and winter months when solar output is reduced.

Using both wind and solar energy sources together can improve the stability and reliability of renewable power generation. The complementary outputs of wind and solar ensure a more consistent energy supply. This mitigates the inherent variability of individual renewable sources. It also increases utilisation rates for downstream plants and reduces the need for costly energy storage systems.

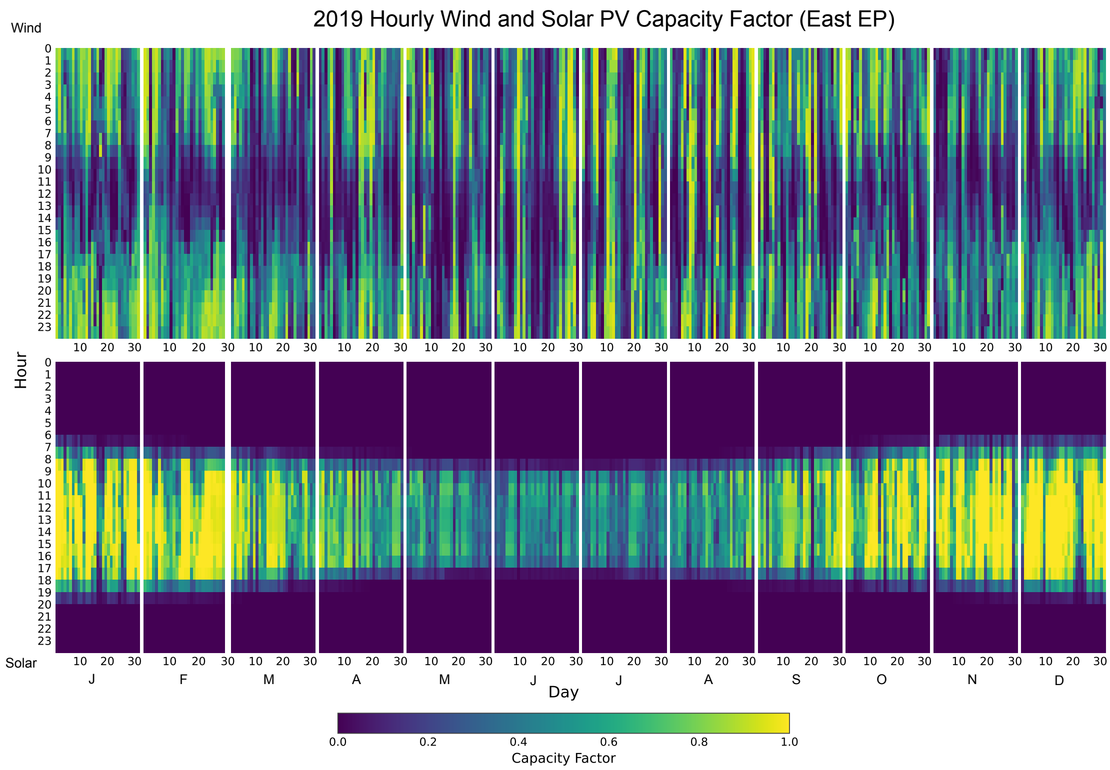

Figure 3: The input wind (upper) and solar PV (lower) capacity factors across 2019 for East Eyre Peninsula demonstrate temporal complementarity. Wind generation peaks overnight while solar peaks during daytime hours, with some seasonal solar PV production decreases evident in winter months. Data source: AEMO ISP 2022 [5]

4. Green Iron Production Model

We use a Mixed Integer Programming (MIP) model called "MUREIL-Steel", previously developed at Monash University [2, 3], to assess the potential for green steel production at specific sites considering the underlying temporal variability of local renewable resources. MUREIL-Steel evaluates the impact of the temporal operational flexibility of electrolysers and the smelting process on the optimal design of a green iron/steel production system based on hourly wind and solar data.

A schematic outline of the major components in the off-grid MUREIL-Steel model is presented in Figure 4. The hydrogen-based direct reduction (HDR) process involves pre-heating iron ore and feeding it into a reduction shaft furnace. The iron ore is then transformed into direct reduced iron (DRI). A condenser pre-heats the hydrogen produced by an electrolysis unit before supplying it to the shaft as a reducing agent. DRI is melted in an electric arc furnace, where it is formed into liquid steel.

This study focuses on South Australia's green iron supply chain and excludes the steel smelting processes (enclosed by dotted lines in Figure 4) to be carried out by potential trade partners. To facilitate iron storage and shipment, DRI needs to be compressed into HBI at high temperatures. This is because DRI, known as "sponge iron", is highly porous and reactive, posing hazards from rapid corrosion, reoxidation, hydrogen gas generation, and even combustion and explosion [6]. Compacting it into denser HBI briquettes mitigates these risks and allows for easier and safer stacking, loading, unloading and transportation. Once formed into briquettes, the HBI is cooled down before further handling. The briquettes must be kept dry by covering or containing them, as HBI can react detrimentally with water [7]. The dense HBI briquettes can be efficiently transported in bulk by truck and loaded into the holds of bulk carrier ships. Ensuring the HBI remains dry throughout shipping is critical, as seawater exposure leads to oxidation and degradation.

The model assumes that electricity for powering electrolysers, the hydrogen direct reduction furnace, and the electric arc furnace for steel manufacturing can be supplied by onsite wind, solar PV, or a hybrid wind-solar PV system. This system may be supported by a 2, 4, or 8-hour battery energy storage system (BESS) to manage renewable diurnal variation and a hydrogen buffer tank for seasonal variation. Cost-optimal system designs are calculated among the generation and storage options to meet specified green iron production targets (such as 500ktpa or 2.5mtpa in this analysis). The MUREIL-Steel model searches for the optimal (i.e., least-cost) configuration of all components based on the simulated hourly operation of the plant, subject to any imposed production constraints.

5. Techno-Economic Parameters

The modelling seeks to quantify the benefit of system flexibility in iron manufacturing. While this study does not cover steelmaking, it provides the techno-economic parameters in the appendix for downstream steel modelling, enabling other EU modellers to conduct further analysis.

Matching variable renewable generation with electrolysis and smelting plants is a significant challenge.

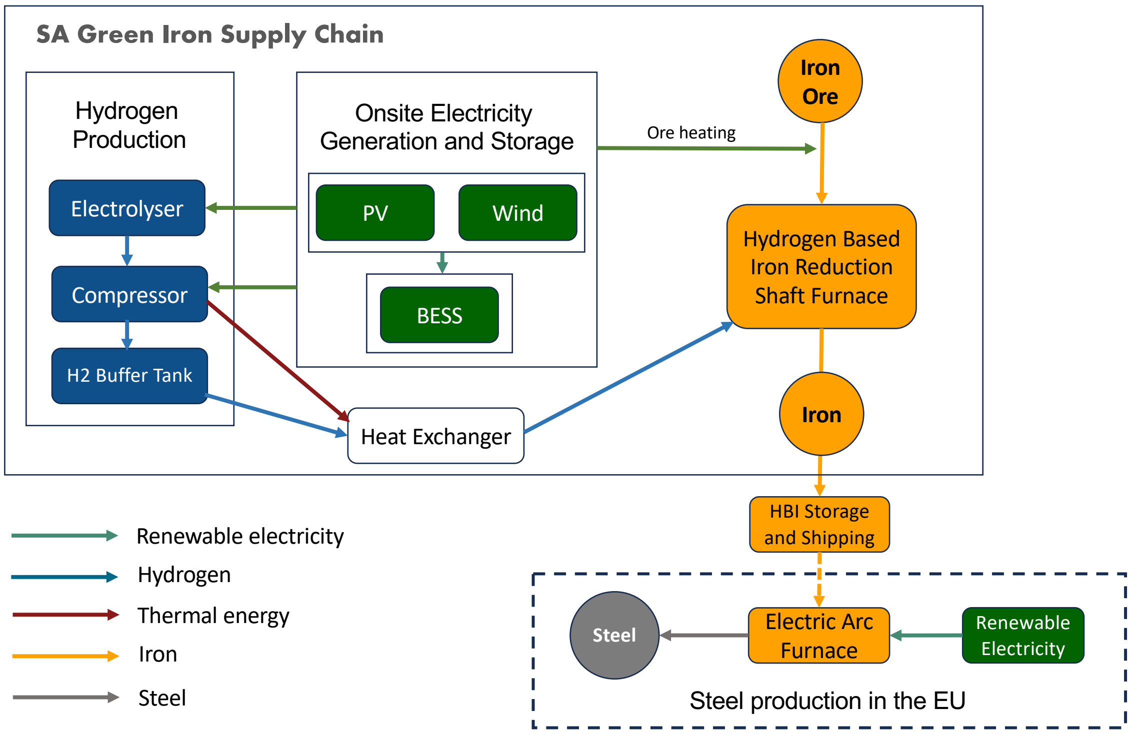

Figure 4: Schematic illustration of the key elements examined in the South Australian iron supply chain study (enclosed by solid lines) and the subsequent downstream processing undertaken by European trade partners (enclosed by dotted lines). The downstream steel smelting processes fall outside the scope of this study.

Of the available electrolyser technologies, proton exchange membrane (PEM) electrolysers possess the highest operational flexibility and turndown capability [8]. They are also expected to have the greatest potential for cost reductions [9]. For these reasons, we select PEM over other technologies for hydrogen production modelling. If the electrolyser is sized larger than required for operation at a 100% utilisation rate, flexibility can be added to the system to cope with renewable variability while meeting the production target.

Hydrogen storage tanks enable providing backup hydrogen capacity when renewable generation is low. Smelting plants are typically much less flexible in operation and require constant hydrogen inflow to maintain a steady-state reaction. We incorporate an intermediate, low-pressure hydrogen storage system to buffer the variations in hydrogen production. Today, most PEM electrolysers operate with hydrogen outlet pressures between 30 and 40 bar [10]. Compressing hydrogen from 30-40 bar to 100 bar for storage is practical and efficient. It requires a compressor, but as the initial pressure is already relatively high (30-40 bar), the energy required for further compression to 100 bar is less than if starting at atmospheric pressure. For consistency, pressurized gaseous hydrogen storage in tanks is modelled here based on typical site constraints. While 100-bar tank storage is assumed, site specifics may favour high-pressure vessels, despite needing more electricity for compression, if space is limited or overall costs are lower. Future work could examine ultra-high-pressure or underground options if site characteristics permit.

Apart from hydrogen tank storage, lithium-ion batteries help balance short-term fluctuations in renewable generation. Batteries can smooth out the hourly and daily solar and wind variability. This enables the electrolyzers to achieve a higher utilisation rate despite variations in renewable generation. Oversizing wind and solar PV is also a strategy to increase electrolyzer utilisation rate, although it leads to more renewable curtailment. The optimization model examines the costs and benefits of adding batteries, oversizing PEM electrolyzers, oversizing wind and solar PV, and installing hydrogen storage tanks, subject to system operational constraints.

Financial input assumptions are also critical to techno-economic modelling. Key renewable generation technology capital expenses are taken from the AEMO's 2022 ISP [5] Inputs and Assumptions Workbook (under the "Step Change" scenario) as summarised in Table 1. We assume hydrogen tank storage at A$600/kg (A$18/kWh), which is in line with [11] and [12]. Most of the plants (including iron and steel plants) are assumed to have an economic life of 20 years [13], whereas lithium-ion batteries are assumed to have a lifetime of 15 years. This battery assumption aligns with the 15-year warranty provided for Tesla's Powerpack 2 units of the Hornsdale project in South Australia [14]. The PEM stack lifetime is assumed to be 80,000 hours of operation (i.e., around 10 years). The discount rate (DR) is assumed to be 7.5%, which is in line with the ISP [5].

In our economic analysis of PV systems, PEM electrolysers, and battery installations, we utilised a power-law relationship to encapsulate the economies of scale. This relationship is captured by the formula $C = a \times S^b$, where C represents the cost per unit, S denotes the size or scale of the installation, and a and b are constants. The scaling factor b quantifies the rate of cost reduction as size increases. Based on a preliminary review of historical data and industry trends, we have broadly estimated the scaling factor b to be approximately -0.1 for PV [15], PEM [16], and battery technologies [17] in our initial cost modelling. This estimated value provides a reasonable starting point for initial economic calculations but should be further validated through empirical data fitting before drawing definitive conclusions. Applying this factor, the cost for a system that is five times larger (represented as $5^{-0.1}$) yields a multiplier of approximately 0.7943. This implies that with each unit increase in size, the unit cost diminishes to around 79.43% of its preceding value. Furthermore, we operate under the assumption that the CAPEX projections for 2030 from AEMO's ISP cater to large, utility-scale generation systems (aligned with the 2.5 mtpa case). For systems five times smaller (equivalent to 500ktpa), we adjust the cost by dividing by the mentioned factor. Given the maturity of wind energy technology and the hydrogen system balance of plant and tank storage, we refrained from applying this scaling factor to these installations in our study.

Additionally, according to [18], there is a correlation between low-cost producers and those with lower raw material costs and production levels that fall below the estimated breakeven scale of operation, emphasizing the importance of economies of scale in iron/steel production. For our analysis, we incorporated a scaling factor of 0.84, in line with [18], for the DRI plant when considering a larger capacity of 2.5 mtpa in comparison to the 500ktpa scenario. This adjustment is a broad assumption made to account for the economy of scale. It is crucial to emphasize that these scaling factors serve primarily as illustrative tools, and the tangible economies of scale might oscillate depending on regional, technological, and market-centric conditions.

This study focuses on system-level implications and excludes detailed process-specific calculations for each production unit. The goal is higher-level analysis rather than modelling minor material and energy flows within individual process steps. We assume it would require 1504 kg of iron ore pellets to produce one tonne of DRI [13]. The operating temperature of the shaft furnace is 800ºC, and the metallisation achieved in the shaft furnace is assumed to be 94% (i.e., from Fe2O3 to Fe, where Wustite (FeO) formation is neglected). This will require 51 kg of hydrogen as a reducing agent per tonne of iron without hydrogen losses [13]. The reaction is endothermic:

$$Fe_2O_3 + 3H_2 \rightarrow 2Fe + 3H_2O_{(g)} \quad \Delta H_R = +99.5kJ/mol$$

The stoichiometric ratio of hydrogen feed to the shaft furnace is 1.5 [13], accounting for kinetic, thermodynamic, variability, and utilisation considerations. Overall, it requires approximately 2.5 MWh per tonne of DRI (54 kg of hydrogen assuming electrolysis efficiency of 72% [13] wrt. hydrogen lower heating value (LHV)), responsible for 73% of the total specific energy consumption [13]. The estimated annual requirements for renewable electricity, hydrogen, and iron ore, as applicable to the 500ktpa and 2.5mtpa production scenarios, are detailed in Table 2.

While downstream processing from iron to steel via electric arc furnace is not examined in this study, the input parameters used in the MUREIL-Steel model for steel production are provided in the Appendix as a reference for further work.

According to [13], electricity consumption for iron ore preheating and the shaft furnace is approximately 0.177 MWh per tonne of DRI. The electricity consumption of the shaft furnace is minimal due to the use of recovered heat from the condenser (Figure 4). It should be noted that the values provided are specific to the iron and steelmaking processes and do not encompass the energy demands required for other activities such as pelletising, secondary metallurgy, casting, and rolling. Pelletising, in particular, requires additional inputs of fuel and electricity [20, 13].

With the energy requirements and plant operational constraints, the MIP model simultaneously optimizes the sizing of onsite wind, solar PV, lithium-ion battery, PEM electrolysers, hydrogen storage tanks, and the iron reduction furnace – excluding the electric arc furnace for steel-making in this analysis – to achieve an annual production target of 500k or 2.5m tonnes of DRI/HBI. The levelized cost of DRI/HBI is then calculated based on plant costs of the optimized system components, operational expenditures, iron ore costs, labour, and production volume, among other factors.

Table 1: Key cost assumptions (in A$) for iron production employed in the MUREIL-Steel Model

Component	Project Start 2030 (500ktpa)*	2030 (2.5mtpa)*
Capital expenditure (CAPEX)		
PEM electrolysers (72% efficiency [13] wrt. LHV of 33.33 kWh/kg)	$1157/kW	$919/kW [5]
Wind	$1848/kW [5]	
Solar PV	$1002/kW	$796/kW [5]
Battery Energy Storage System (2h) (85% round trip efficiency)	$690/kW	$548/kW [5]
Battery Energy Storage System (4h) (85% round trip efficiency)	$956/kW	$759/kW [5]
Battery Energy Storage System (8h) (85% round trip efficiency)	$1524/kW	$1211/kW [5]
H2 tank (with compressor and balance of plant)	$18 /kWh[11]	
Hydrogen Direct Reduction Shaft Furnace	$368/tonne [13] *	$309.1/tonne †
Operational expenditure (OPEX)		
Variable OPEX of wind, solar PV, BESS and PEM	0 [5]	
PEM Fixed OPEX	3% of CAPEX/year[5]	
Fixed OPEX of EAF and H2-DR shaft	3% of CAPEX/year [13]	
H2 tank Fixed OPEX	1% of CAPEX/year [11]	
Wind Fixed OPEX	$28/kW/year [5]	
Solar Fixed OPEX	$19/kW/year [5]	
BESS 2h Fixed OPEX	$12/kW/year [5]	
BESS 4h Fixed OPEX	$19/kW/year [5]	
BESS 8h Fixed OPEX	$31/kW/year [5]	
Labour (DRI/HBI)	$8.3/tonne ‡ [19]	

*The Sweden's HYBRIT model [13] - based on nameplate capacity, *i.e.*, annual capacity at 100% operation. Euro to AUD exchange rate of 1.6 was used.

†Scaling factor of 0.84 [18] was used due to economy of scale

‡Assuming 73 full-time equivalent (FET) per Mt of DRI at an hourly rate of $57 [19].

Table 2: Projected Annual Requirements for DRI Production

Production Target	**Electricity for Ore Heating (GWh)**	**Electricity for Hydrogen Production (GWh)**	**Total Electricity (GWh)**	**Total Hydrogen (tonne)**	**Total Iron Ore Pellets**
500ktpa	88.5	1,180.4	1,268.9	25,500	752ktpa
2.5mtpa	442.5	5,902.2	6,344.7	127,500	3.76mtpa

6. Results

6.1. Renewable Electricity

For the disaggregated supply chain scenario, reliable electricity can be secured by entering into a Power Purchase Agreement (PPA) with an external provider. The PPA between BHP and Neoen serves as a relevant example of this practice. This industrial PPA [21] is specified to ensure a consistent supply of electricity to BHP's Olympic Dam operations, utilising wind energy complemented by battery storage to achieve 24/7 baseload capabilities.

Using the MUREIL model described above, we determine cost-optimal configurations and renewable electricity rates (based on a hybrid wind/solar/battery system) for the East Eyre Peninsula. However, constructing a 24/7 off-grid renewable energy system that offers uninterrupted "baseload" electricity is expensive, as it requires massive storage capacity and renewable overcapacity. The modelling results indicate that by 2030, an optimally designed renewable electricity system could provide 100% reliable power at a rate of A$174.6/MWh by independent power producers.

Renewable electricity costs can be lower with reduced availability, but it necessitates installing an oversized electrolyser operating at a lower capacity factor to maintain the same hydrogen production levels. This creates a trade-off between operational costs (i.e., electricity costs) and the capital investment in electrolysers. Figure 5 shows the modelled renewable electricity generation costs at various full-load hour supplies (i.e., utilisation rates or capacity factors) across the year. As the number of full-load hours decreases from a continuous 8760-hour annual operation, the electricity cost is reduced due to lower renewable overcapacity and storage requirements in the optimized system designs. Overall, to generate the same output, producers would need to install larger electrolyzers operating at lower utilization rates.

Some downstream processes may be unable to flexibly ramp up and down due to technical constraints and high-temperature reactions. For example, while electrolyzers have flexibility, direct reduction furnaces would require a constant hydrogen supply to maintain temperatures, which may necessitate onsite hydrogen storage. Simply overbuilding and assuming lower capacity factors for downstream plants fails to capture these practical limitations in some cases. So, although the underlying electricity costs decline at lower full load hours, complementary infrastructure must be considered in applying these projections to process systems with continuous steady-state operation (e.g., constant hydrogen inflow) requirements. This calls for vertically integrated system planning and a holistic optimisation approach.

For the disaggregated scenario requiring renewable electricity input, such as iron ore heating, we utilise a conservative electricity rate estimate of A$0.18/kWh. This projection reflects the optimized 24/7 renewable power costs potential for the region. Although heating demands may not call for continuous operation in practice, we assume full-time running, which is conventional to establish an upper-bound system reliability and production cost benchmark. Furthermore, this flat supply profile provides an electricity input basis to calculate associated hydrogen and iron production costs in the disaggregated scenario across alternative supply chain configurations. Applying high-availability and peak renewable pricing envelops process economics for wide-ranging market conditions and industrial use cases tied to regional renewable rollout forecasts through 2030.

6.2. High-Grade Iron Ore Pellets

An internationally competitive iron ore pellet price is an appropriate reference point across both our integrated and disaggregated scenarios. Based on consultations with DEM industry experts, we have established a Free Board (FOB) global DRI pellet price assumption of A$200/tonne. As per industry advice, even for the integrated scenarios where pellet production is part of the vertically integrated green iron value chain, the resultant pellets should still be evaluated based on international market pricing as an opportunity cost.

Table 3 provides a comprehensive benchmark analysis of five operating magnetite mines worldwide, including key information on production metrics and final DRI pellet costs. World Mine 1 and World Mine

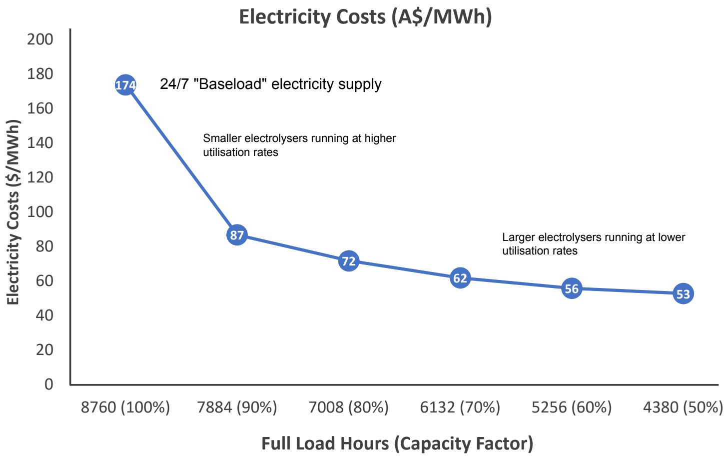

Figure 5: Modelled renewable electricity generation costs based on a hybrid wind/solar/battery system. Costs are shown at different full-load hours and corresponding utilisation rates (i.e., capacity factors). Lowering the availability of renewable electricity can reduce costs, but it requires a larger electrolyzer that operates less frequently to sustain the same level of hydrogen production.

2 serve as the most relevant benchmark references - both are large, global-scale magnetite mines currently in operation, with fully built-up costs ranging from A$189-196 per tonne. With a FOB export price of A$200 per tonne, these two sizable mines would achieve a return slightly above the standard 7.5% Internal Rate of Return (IRR) target.

Our assumed FOB price assumption is also in line with industry pricing dynamics. Specifically, an equivalent historical average Cost and Freight (CFR) China pellet price of US$150 per tonne at the China port[1], less an A$25/tonne adjustment for shipping to determine a comparable FOB Australia export price, results in a similar FOB price of A$200 per tonne. This is consistent with the cost structures at the aforementioned operating mines in Table 3. Given the industry guidance and feedback, we believe A$200 per tonne is a reasonable long-term global benchmark pellet pricing assumption for evaluating the economics of both our integrated and disaggregated mining scenarios.

AISC by Mine	World Mine 1	World Mine 2	World Mine 3	Australian Mine 1	Australian Mine 2
Concentrate or Pellet Production (Mt p.a.)	19.2	14.4	10.0	2.1	2.5
FOB Concentrate Cost per template 1	54	66	122	73	70
Pellet Conversion Cost	25	25	25	29	29
Quality upgrade to DRI spec	included	included	included	6	6
Royalties (@ US$140/t realised fob price)	11	3	6	6	8
Fully built up AISC DRI Pellet FOB	90	95	153	114	113
Cost-of-Capital Charge (7.5% real WACC) 2, 3	42	42	42	42	42
Final AISC DRI Pellet Cost FOB (US$/t)	132	137	195	156	155
Final AISC DRI Pellet Cost FOB (A$/t) 4	189	196	279	223	222

Table 3: Iron ore pellet project benchmark

Notes:
1. Includes sustaining capex and logistics to sea port.
2. Pre-tax margin (US$42/t) required to generate a 7.5% real, after-tax cost of capital return.
3. Capex based on Iron Bridge US$3.8 billion + estimate US$1.0 billion for concentrator upgrade to DRI spec and Pellet plant i.e. US$250/t pellet capacity.
4. At assumed 0.70 US$/A$.

[1] Specifically, the portside prices in China for 65% iron ore pellets currently stand at approximately $150 USD (225 AUD) per tonne, down from a high of approximately US$300 (A$450) per tonne in May 2021 [22].

6.3. Green Hydrogen

In our evaluation of hydrogen suppliers, we consider two distinct systems. The first system operates with a 100% capacity factor, ensuring continuous operation. The second system, on the other hand, strategically optimizes both the capacity factor and the plant size to reliably satisfy the daily hydrogen requirements of the DRI plant. Our analysis reveals that as the cost of electrolysers decreases, operating them at reduced utilisation rates becomes more economically viable. Nevertheless, to maintain a steady daily supply amidst such variability, a more substantial buffer tank is essential. When operating under full load, the cost stands at A\$8.79/kg. In contrast, modelling results show the optimized system, which operates at a 56% utilisation rate, offers a cost of A\$5.62/kg. Both costs account for hydrogen storage.

6.4. Green DRI/HBI

For the integrated supply chain, the model simulates and optimises the hourly operational dynamics of the integrated green iron production facility across a full year. Figure 6 displays a snapshot of the modelled hourly operation for one example day (August 4, 2030) in the East Eyre Peninsula using 2019 renewable energy data representing a projected future year. The 2.5mtpa integrated production system combines wind, solar PV, battery storage, electrolyzers, hydrogen tanks, and the HDR shaft furnace. During daylight hours, solar generation mainly powers the electrolyzers and system loads. Any excess electricity is stored in batteries and as hydrogen in tanks. Solar power curtailment peaks around midday when generation exceeds demand. After sunset, wind energy, discharged battery storage, and hydrogen from the tanks sustain continuous system operation and the iron reduction reaction throughout the night. This interplay between diverse renewable generation assets and storage options buffers variability, enabling uninterrupted green iron production, as shown by the stable output line in Figure 6.

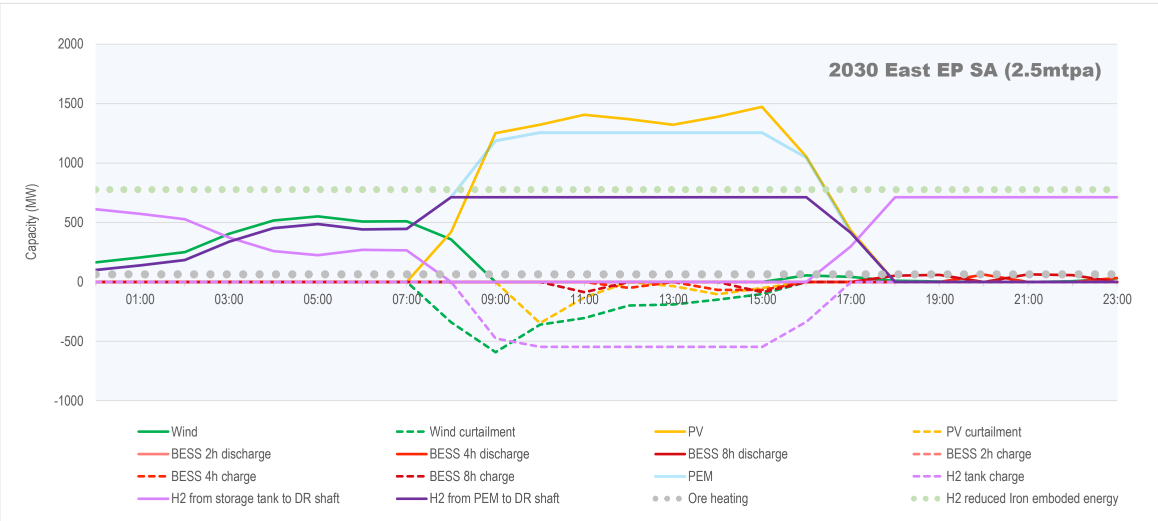

Figure 6: Example of simulated hourly operation of the 2.5mtpa h2-DRI system powered by wind and solar with support of battery and hydrogen storage in 2030 in East Eyre Peninsular. To maintain stable iron output, system control strategies guarantee a reliable hydrogen feedstock supply at constant inlet conditions. The wind and solar capacity factor input was based on AEMO ISP data on August 4, 2019 at East Eyre Peninsula in South Australia.

Adopting an integrated production system, which encompasses mining, pelletization, and the entire spectrum of iron making, presents distinct advantages. Such a system that seamlessly combines wind and solar energy to power green hydrogen production, iron ore heating, and the broader manufacturing process can lead to notable cost and efficiency gains. This is evident when comparing the integrated approach against scenarios where hydrogen production and HBI manufacturing are disaggregated entities in the supply chain. The cost analysis, comparing integrated versus disaggregated HBI production, is summarized in Table 4 and Figure 7,

From Table 4 and Figure 7, a 500ktpa integrated HBI production system incurs an HBI/DRI production cost of A$720.5 per tonne. This cost is segmented into contributions from ore heating and hydrogen (A$365.1), iron ore (A$300), labour (A$8.3), and the HBI plant (A$47.1). Further, a larger-scale 2.5mtpa integrated HBI system reduces the cost of the process to A$678.3 per tonne due to inherent economies of scale and integrated efficiencies, with a significant portion allocated to ore heating and hydrogen (A$330.4).

To evaluate sensitivity to the discount rate, we set a risk-free benchmark rate (excluding mining and pelletization) based on the 10-year Australian government bond yield of 4.57% [23] as of November 24, 2023. This government bond yield represents the minimum return threshold for a private investment. By reducing the discount rate from 7.5% to the current 10-year bond yield, the model calculates a 9.3% decrease in the cost of integrated iron production, from A$678.3/tonne to A$615.5/tonne in the 2.5mtpa system.

Cost reductions from further lowering the discount rate highlight the significant impact of supportive government financing policies. An interest-free loan and policy support for the green iron supply chain could greatly reduce production costs. In our analysis, we applied a 0% discount rate, made feasible by potential government incentives like zero-interest loans and capital expenditure assistance. These incentives dramatically change the project's financial landscape, enabling an assessment that illustrates the project's value without the complexities of the time value of money and external financing costs. This foundational assessment, using a 0% rate as a starting point, aims to provide stakeholders with a clear view of the project's potential in current terms. Nevertheless, it's important to recognize the need for a more comprehensive discount rate in real-world scenarios, considering various risks such as operational, market, and regulatory factors. Subsequent analyses should include these considerations to reflect a more complete view of risks and opportunity costs. By excluding the discount rate from the capital expenditure, our model shows a 21.8% decrease in the cost of integrated iron production, from A$678.3/tonne to A$530.8/tonne at a 2.5mtpa scale. This demonstrates the role of concessional financing and government support in enhancing the viability of green iron projects.

In contrast, a disaggregated supply chain for HBI at 2.5mtpa with full-load operations results in a cost of A$862.2 per tonne, distributed among ore heating (A$39.6), hydrogen (A$474.7), iron ore (A$300), labour (A$8.3), and the HBI plant (A$39.6). An optimized version of this disaggregated approach, operating at a 56% utilisation rate, achieves a cost of A$691 per tonne. These two disaggregated scenarios – one with full-load hours and one optimized at part-load of hydrogen production with onsite hydrogen tanks—establish upper and lower bounds for production economics across disaggregated supply chain configurations. Comparing these values to integrated approaches provides insights into achieving cost-competitive renewable hydrogen-based iron manufacturing through both centralized and distributed industrial ecosystems.

Clearly, the integrated green iron supply chain yields superior economic outcomes compared to the disaggregated scenarios. One key benefit of this integrated approach is the ability to produce hydrogen on-site, which eliminates the need for additional storage and transport infrastructure. Moreover, integrating renewable energy not just for hydrogen production but also for ore heating and iron manufacturing optimizes electrolyzer usage. This holistic planning approach leads to more consistent and efficient energy utilisation throughout the value chain, further strengthening the argument for adopting integrated systems in the production of green iron.

Table 4: Comparison of HBI Production Costs

Parameters	**500ktpa Integrated HBI**	**2.5mtpa Integrated HBI Supply Chain HBI**	**2.5mtpa Integrated HBI Supply Chain HBI (10-year bond)**	**2.5mtpa Integrated HBI Supply Chain HBI (interest-free loan)**	**2.5mtpa Disagg. (full-load)**	**2.5mtpa Disagg.**
RE electricity	-	-		-	A$174.6/MWh	A$174.6/MWh
RE electricity FLH	-	-		-	8760 hours	8760 hours
H2 costs (incl. storage)	-	-		-	A$8.79/kg	A$5.62/kg
H2 Full Load Hours	5041 hours	4995 hours	4972 hours	4975 hours	8760 hours	4912 hours
HBI/DRI	A$720.5 = 365.1 (ore heating and h2) + 300[1] (iron ore) + 8.3 (labour) + 47.1 (HBI plant)	A$678.3 = 330.4 (ore heating and h2) + 300[1] (iron ore) + 8.3 (labour) + 39.6 (HBI plant)	A$615.5 = 274.0 (ore heating and h2) + 300[1] (iron ore) + 8.3 (labour) + 33.2 (HBI plant)	A$530.8 = 197.8 (ore heating and h2) + 300[1] (iron ore) + 8.3 (labour) + 24.7 (HBI plant)	A$862.2 = 39.6 (ore heating) + 474.7 (h2) + 300[1] (iron ore) + 8.3 (labour) + 39.6 (HBI plant)	A$691.0 = 39.6 (ore heating) + 303.5 (h2) + 300[1] (iron ore) + 8.3 (labour) + 39.6 (HBI plant)
HBI Full Load Hours	8760 hours	8760 hours	8760 hours	8760 hours	8760 hours	8760 hours

Notes:

1. Assuming that it takes 1.5 tonnes of iron ore to produce 1 tonne of iron [13].
2. Electricity consumption for iron ore preheating is approximately 0.177 MWh per tonne of DRI [13]. In the integrated production model, the capacity of renewable energy sources and storage systems must be sufficient not only for hydrogen production but also for additional requirements such as powering processes like ore heating. Sizing the renewable energy system a bit larger to accommodate this extra demand leads to an increase in full-load hours for integrated electrolysis to 4995 per year. This results in better utilisation of the electrolyzer compared to the 4912-hour optimized disaggregated case, where the renewable capacity is solely dedicated to meeting hydrogen production needs.

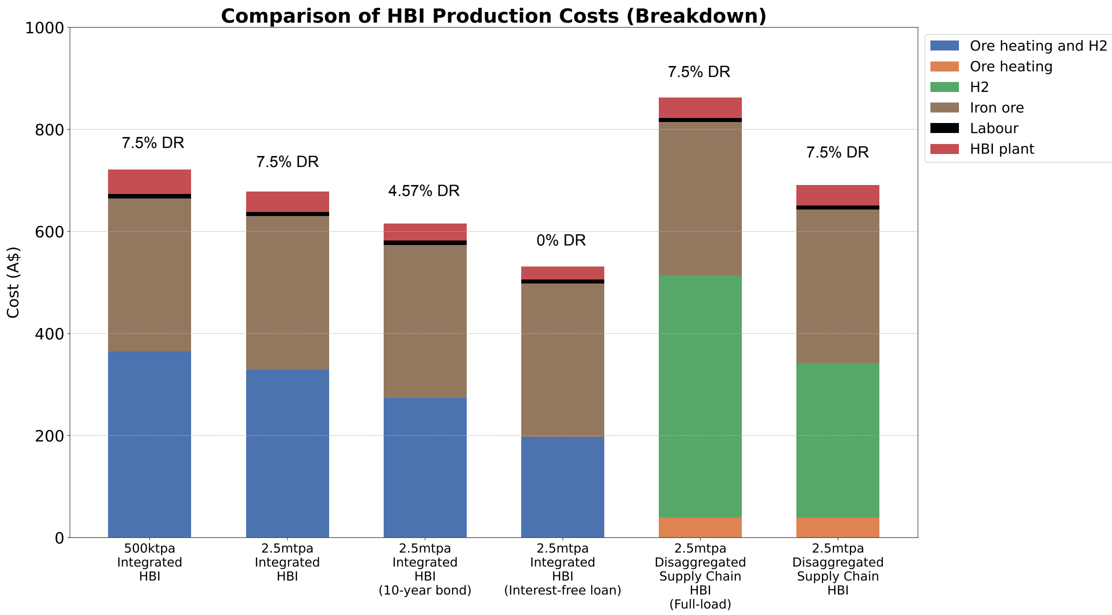

Figure 7: Comparison of HBI Production Costs with various discount rates (Breakdown)

6.5. Other Considerations for HBI

HBI cools to ambient temperature when stored long-term or shipped over extended distances. As a result, extra energy is required to reheat the HBI to suitable temperatures before further smelting. According to research by Vogl et al. [13], using cold HBI that must be reheated consumes 159 kWh/tonne more electricity than directly charging hot DRI/HBI from the shaft furnace into the EAF. While proper insulation and heat retention can prevent the need for separate reheating, this is less feasible given the long shipping distance and duration from Australia to the EU trade partners.

7. Conclusion and Future Work

This preliminary analysis demonstrates the potential for green iron production in South Australia, leveraging abundant renewable resources and integrated production efficiencies. Modelling wind, solar, and storage systems to power integrated iron ore reduction reveals significant cost reductions compared to disaggregated pathways, underscoring the value of on-site electrolysis and process integration.

While this analysis highlights South Australia's strategic opportunity to develop green metals industries, further research can help refine the modelling and provide additional insights.

- *Magnetite Resource Assessment:* Detailed geological surveys and techno-economic analyses should be conducted to quantify magnetite resources in South Australia and evaluate mining methods, processing requirements, and waste management strategies.
- *Technology and Process Modelling:* The green iron production pathway process modelling and energy balance calculations should be further refined with industry feedback to validate and improve cost assumptions. This present work only considers the HYBRI technology. Alternative technologies

such as fluidised-bed and direct electrolysis should also be analysed, along with assessing the effects of ore quality on hydrogen consumption levels. Testing the suitability of various iron production technologies specifically for South Australian ores can better inform technology selection and overall system design.

- *The Role of Natural Gas:* Some direct reduced iron technologies (e.g., MIDREX [24]) can utilise both natural gas and hydrogen as reducing agents. Examining the associated carbon pricing that makes renewable hydrogen cost-competitive with various natural gas price projections could inform the conditions and timeline for fully transitioning from natural gas to green hydrogen for iron production. Additionally, this dual natural gas-hydrogen capability may provide a risk mitigation strategy to maintain high asset utilisation during hydrogen shortages in renewable droughts. Further analysis can weigh the trade-offs between this backup natural gas pathway against oversizing system components or including large hydrogen storage to reduce methane usage.

- *Infrastructure and Logistics:* Costs and requirements should be assessed for port expansions, hydrogen pipelines, and inland transport logistics to connect mine sites, production hubs, and demand centres.

- *Market, Policy and Supply Chain Analysis:* Government policy incentives should be evaluated for potential cost reductions. Revenue opportunities from by-products and grid services should be analyzed. Export and domestic market demand projections and supply chain configurations should be modelled to identify the most attractive regions and product forms for green iron and steel.

By expanding the modelling across these additional aspects, the feasibility projections and strategic recommendations for green iron and steel production in South Australia can be strengthened further. This will support the state's development as a globally competitive green metals hub.

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9. Appendix - Steel Production

For the complete green steel value chain, a specific energy consumption (SEC) of 3.48 MWh per tonne of virgin steel was derived by [13]. An electric arc furnace requires 0.753 MWh per tonne of liquid steel when processing pure DRI without any scrap. For 24/7 operation on 100% hot briquetted iron, producing one tonne of liquid steel requires approximately 1504 kg of iron ore pellets (assuming the ratio of steel output to HBI input is approximately 1:1) [13].

Flexible electric arc furnace operation is currently practical and in use to process scrap metal feedstock within Australia (e.g. [25]). The EAF can operate intermittently, providing the flexibility for steel mills to adjust energy consumption in response to factors such as electricity prices or on-site variations in renewable energy generation.

The MUREIL-Steel model also incorporates scrap charge and HBI storage operations to enable additional flexibility when modelling integrated steel production systems. These flexible operations can help adjust EAF electricity consumption to renewable supply availability across different timescales.

To facilitate further study on downstream steel manufacturing, the CAPEX of the electric arc furnace in both the 500 ktpa and 2.5 mtpa scenarios are listed in Table 5, respectively. The steel manufacturing process also requires 11 kg of alloys, 2 kg of graphite electrodes and 50 kg of lime for each tonne of liquid steel produced [13]. The costs of these consumables and other operational expenses are also listed in Table 5.

Table 5: Key cost assumptions for EAF steel production (in A$) employed in the MUREIL-Steel Model

Component	Project Start	
	2030 (500ktpa)*	2030 (2.5mtpa)*
Capital expenditure (CAPEX)		
Electric Arc Furnace	$294.4/tonne [13] *	$247.3/tonne †
Operational expenditure (OPEX)		
Non-fuel OPEX for steelmaking (lime, alloys, graphite electrodes, etc.)	$51 /tonne crude steel [13]	
Fixed OPEX of EAF	3% of CAPEX/year [13]	
Labour (EAF)	$19.0/tonne ‡ [19]	

*The Sweden's HYBRIT model [13] - based on nameplate capacity, *i.e.*, annual capacity at 100% operation. Euro to AUD exchange rate of 1.6 was used.

†Scaling factor of 0.84 [18] was used due to economy of scale

‡Assuming 167 FET per Mt of steel at an hourly rate of $57 [19].

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