Roadmap to decarbonisation

Mining in a low-emissions economy

Report collaborators

This work reflects the specialist focus areas of the CEFC and MRIWA, and our shared commitment to the growth and development of the Australian mining sector as part of our clean energy transition. We thank specialist consultants ENGIE Impact for their detailed insights and analysis.

CEFC investing to achieve net zero emissions

The CEFC is a specialist investor at the centre of efforts to help deliver on Australia's ambitions for a thriving, low emissions future. With a strong investment track record, we are committed to accelerating our transition to net zero emissions by 2050. In addressing some of our toughest emissions challenges, we are filling market gaps and collaborating with investors, innovators and industry leaders to spur substantial new investment where it will have the greatest impact. The CEFC invests on behalf of the Australian Government, with a strong commitment to deliver a positive return for taxpayers across our portfolio.

MRIWA and the *Net Zero Emission Mining Challenge*

With the global shift towards decarbonisation, the need for mineral resources to support the energy transition places Western Australia at the forefront of a significant economic opportunity. The Minerals Research Institute of Western Australia (MRIWA), a WA State Government statutory body, fosters and promotes minerals research for the benefit of WA. Through its *Net Zero Emission Mining Challenge*, MRIWA is working across the sector to showcase innovation and help capture the benefits of net zero emission mining.

ENGIE Impact and the sustainability transformation

ENGIE Impact is the consulting arm of the global ENGIE Group, the world's largest independent power company. ENGIE Impact works with organisations to embed sustainability in their operational strategies, capturing the economic value of sustainability commitments to lift long-term competitiveness. It applies data analytics, multi-disciplinary expertise and global reach, developing tailored roadmaps to help organisations establish and achieve their sustainability goals, across energy, water, waste and carbon.

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About mining in a low-emissions economy

Australia's mining and resources sector has a critical role to play in the transition to net zero emissions by 2050. The potential is enormous, as are the benefits.

But where are the opportunities? What should be prioritised? And how do we turn ambition into action?

These questions are addressed in this practical analysis, developed by the Clean Energy Finance Corporation (CEFC) and Minerals Research Institute of Western Australia (MRIWA), drawing on the expertise and insights of specialist consultants, ENGIE Impact.

The information is applicable to mining executives, operational leads and sustainability teams. It is presented in a package of three interlinked documents.

Mining in a low-emissions economy

Essential information for junior and mid-tier mining companies seeking to capture the economic and sustainability benefits of our low-emissions future, in three practical and up-to-date documents:

1. The compelling case for decarbonisation	2. Technology solutions for decarbonisation	3. Roadmap to decarbonisation
The next frontier of sector growth, for industry leaders and executives.	Comparative analysis of proven and emerging technology options.	Understanding what to prioritise, drawing on a simulated mining operation.

Download all three documents via: **cefc.com.au** or **mriwa.wa.gov.au**

The focus of ***Mining in a low-emissions economy: Roadmap to decarbonisation*** is on **how to plan a zero-carbon mine**. It provides insights into the use of scenario analysis, decarbonisation pathways and techno-economic assessment as tools for **developing asset-level decarbonisation roadmaps**.

Cover photo credit: Tristan Freemantle – Gold Fields Australia

Glossary

Term	Description
°C	Degrees Celsius
ABGF	Australian Business Growth Fund
ACCU	Australian Carbon Credit Unit
ANE	Ammonium Nitrate Emulsion
ANFO	Ammonium Nitrate Fuel Oil
ARENA	Australian Renewable Energy Agency
ASIC	Australia Securities and Investment Commission
AVL	Australian Vanadium Limited
BaU	Business-as-usual
BECCS	Bioenergy Carbon Capture and Storage
BEV	Battery Electric Vehicle
BELV	Battery Electric Light Vehicle
BESS	Battery energy storage system
$CaCO_3$	Calcium Carbonate
CAES	Compressed air energy storage
CAPEX	Capital Expenditure
CCGT	Closed-Cycle Gas Turbines
CCS	Carbon Capture Storage
CDP	Carbon Disclosure Project
CEFC	Clean Energy Finance Corporation
CER	Clean Energy Regulator
CH_4	Methane
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CRI	Commercial Readiness Index
CST	Concentrated Solar Thermal
Deep decarbonisation	A term to describe moving into the 'hard to abate' decarbonisation projects
DER	Distributed Energy Resources
DoD	Depth of Discharge
DPM	Diesel Particulate Matter
DR	Demand Response
ECF	Energy Content Factor

Term	Description
EDR	Economically Demonstrated Resources
EF	Emission Factor
EMC	Electric Mine Consortium
ERF	Emissions Reduction Fund
ESG	Environmental, Social and Governance
EV	Electric Vehicle
FCEV	Fuel Cell Electric Vehicle
FFI	Fortescue Futures Industry
FMG	Fortescue Metals Group
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GWh	Gigawatt-hour
GWP	Global Warming Potential
H_2	Hydrogen
IA	Idemitsu Australia
ICE	Internal combustion engine
ICP	Internal Carbon Price
IEA	International Energy Agency
IP	Ingress Protection
IPCC	In-pit crushing and conveying
IRR	Internal rate of return
ICSV	ICMM's Innovation for Cleaner, Safer Vehicles
J	Joule
k	kilo
L	litre
LGC	Large-scale Generation Certificates
Li-ion	Lithium-ion battery
LNG	Liquified Natural Gas
LRET	Large-scale Renewable Energy Target
m	metre
M	Mega
M	Million

Term	Description
MJ	Megajoule
MoU	Memorandum of Understanding
MVR	Mechanical Vapour Recompression
MW	Megawatt
MWh	Megawatt-hour
N_2O	Nitrous Oxide
NGERS	National Greenhouse and Energy Reporting Scheme
NWIS	North West Interconnected System
OCGT	Open-Cycle Gas Turbine
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
PHEV	Plug-in hybrid electric vehicle
PPA	Power Purchase Agreement
PV	Photovoltaic
R&D	Research and development
REC	Renewable Energy Certificate
ROM	Run of mine
SBT	Science-based Targets
Scope 1	Scope 1 emissions are direct emissions, that occur from sources that are controlled or owned by an organisation
Scope 2	Scope 2 emissions are indirect emissions associated with the purchase of electricity, steam, heat or cooling
Scope 3	Scope 3 emissions are the result of activities from assets not owned or controlled by the reporting organisation
SDGs	United Nations Sustainable Development Goals
SLL	Sustainability Linked Loan
SMR	Steam Methane Reforming
SPS	Standalone power system
SSAB	Svenskt Stal AB
SWIS	South West Interconnected System
TA	Trolley assist
tCO_2-e	Tonne of Carbon Dioxide equivalent
TCFD	Taskforce on Climate-related Financial Disclosure
tpa	Tonnes per annum

Term	Description
TRL	Technology Readiness Level
VRE	Variable Renewable Energy
VRFB	Vanadium Redox Flow Battery
VRM	Vertical Roller Mill
WA	Western Australia
WACC	Weighted average cost of capital
Zero carbon	The end state of all GHG abatement activity with no CO_2-e emissions and no reliance on carbon offsets

Moving from intent to action

The case for addressing decarbonisation is clear. Momentum is building, technologies for immediate action exist, and the commercial case is strong. Within Australia, **the demand for low-emissions energy minerals and the decarbonisation of mining is the greatest opportunity to diversify and grow the resources sector in a generation.**

Access to cheaper capital and the mitigation of risks associated with corporate social responsibility and carbon liability are some of the opportunities that decarbonisation can provide. Executives across the mining industry are seeing this and acting to deliver stakeholder and commercial competitive advantages. Those seen to lag are likely to suffer reduced competitiveness and long-term sustainability.

On the back of this shift, the mining industry is experiencing a considerable uptick in decarbonisation commitments. These commitments have come in the form of a stated decarbonisation ambition supported by group-wide emissions reduction targets, usually with an intermediate target and a net-zero endgame. Many of the targets that have been set lack the sufficient depth of disclosure on how those targets will be achieved. As investor and regulator pressure mounts, mining companies will be compelled to clearly demonstrate how targets will be met.

Moving from intent to action is complex. The challenge of decarbonisation is not just setting targets but rather developing and executing a transformational strategy. To meet decarbonisation goals, mining companies should develop asset-level decarbonisation roadmaps and implementation plans.

Creating the zero-carbon mine

The imperative for mining companies is to find the right set of technologies to achieve the zero-carbon endgame for their assets. Most of the technologies that will deliver zero-carbon mining are either already technically and commercially mature or expected to be within the next decade.

Each mining operation is context dependent, with a unique path of decarbonisation. Life of mine, location, access to land, grid connectivity, stage of mine life cycle, type of operations, commodity type, and existing energy infrastructure are among the factors that may present both barriers and opportunities. The right decarbonisation pathway for one mine may vary considerably to another, depending on the context. Adding to the complexity is a technology landscape that is uncertain and accelerating at a rapid pace. With a wide variety of mature technologies and heavy competition between emerging technologies, mining companies need to cut through complexity and uncertainty to make the right investment decisions.

Scenario-based, techno-economic assessments are the method of choice for mining companies to create a roadmap to decarbonisation. This approach applies scenario thinking typically used by strategists, with engineering-grade techno-economic assessment tools, to build and analyse a range of decarbonisation pathways. These pathways can be compared to one another and to a business-as-usual (BaU) base case. The output of this assessment is an actionable, yet flexible, asset-level decarbonisation roadmap. Asset-level roadmaps can then be consolidated to build a group-wide decarbonisation approach and set realistic and achievable timelines.

The use of decarbonisation pathways provides a structured approach for decision makers to group and evaluate technologies while accounting for decarbonisation goals, risks, budget, and other site-related constraints (such as available land). Decarbonisation pathways create optionality to cope with technological uncertainty and a changing commercial and regulatory landscape. They also help distinguish between immediate low-risk ('no regret') capital investments and long-term strategic considerations.

A clear decarbonisation roadmap is crucial for managing the decarbonisation of a mining operation.

An effective roadmap will ideally be:

– **Context driven:** Factor in mine-specific characteristics such as location, mine type, commodity type and the extent of on-site mineral processing.

– **Prioritise technologies:** Clearly outline low-risk technology investments that can be made in the short term.

– **Prioritise emissions:** Preference emissions avoidance ahead of emissions reduction or mitigation.

– **Flexible:** Anticipate the rapidly evolving technology landscape, with medium and long-term flexibility between investment phases to capitalise on emerging solutions.

– **Highly analysis driven:** Use scenario analysis supported by engineering-grade techno-economic assessments.

Building the roadmap

There are several stages in the decarbonisation journey. Key steps in the planning and implementation process to support robust roadmap development are outlined in Figure 1.

Identify

- Develop a baseline energy and emissions profile and BaU trajectory for the life of the mine
- Identify a list of potential decarbonisation projects, understanding how they impact energy consumption and emissions

Target

- Determine the decarbonisation ambition for the mine in the context of group decarbonisation targets
- Work with stakeholders to develop achievable, high integrity targets for both cumulative and annual emissions

Plan

- Construct a range of decarbonisation pathways for the mine
- Undertake a thorough techno-economic assessment of the pathways
- Build the decarbonisation roadmap by back-casting to identify required technology for the end-state
- Include phasing and sequencing for implementation of key initiatives

Implement

- Explore partnerships and financing options to implement decarbonisation projects
- Establish governance and accountability for implementation

Monitor

- Measure and report on progress on an ongoing basis, to keep stakeholders engaged and comply with relevant disclosure frameworks

Figure 1: Moving from intent to action – steps to decarbonisation

Step 1: Identify

Developing a baseline energy and emissions profile for the operation is the first step in the decarbonisation journey. Identifying the BaU trajectory for the life of the mine clearly outlines the comparative contributions to total emissions across each fuel and activity, informing decisions on which activities can be prioritised based on the scale of potential abatement.

An emissions profile can be represented within a tree structure to clearly show the source or activity, as demonstrated in Figure 2.

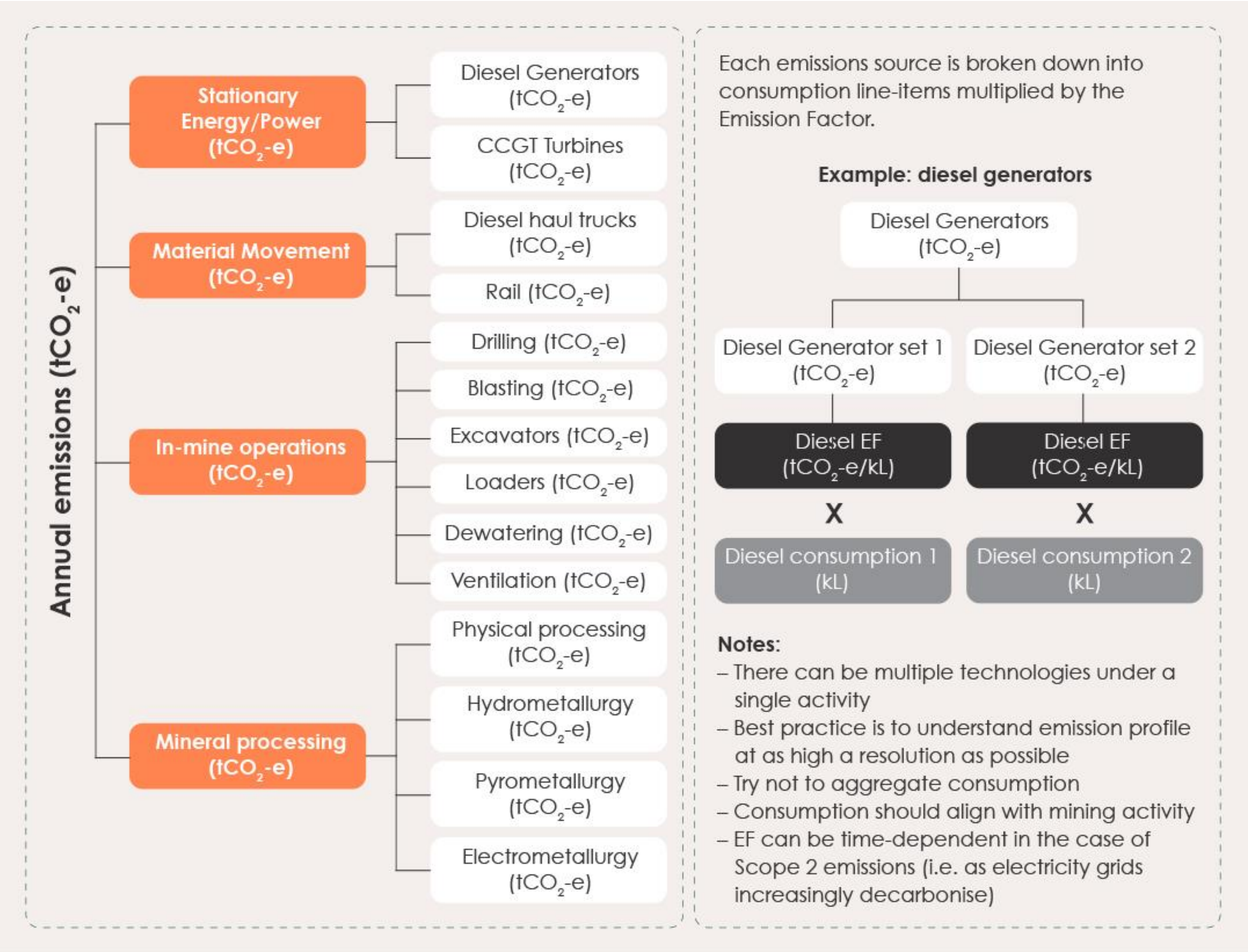

Figure 2: Example structure to represent the emissions profile of a mining operation

BaU is best represented through a *baseline forecast*. This forecast – be it emissions, energy, or consumption – allows the distinction of decarbonisation strategies from a BaU strategy, enabling the impact of the decarbonisation strategy to be calculated.

Once emissions sources have been identified, potential decarbonisation projects can be developed to mitigate certain emissions with a clearer understanding of how they impact overall energy consumption and emissions. Mine expansion and planning decisions will also impact the emissions profile and should be considered at this stage to identify future emissions sources.

Step 2: Target

Work with stakeholders, including operations personnel and financial institutions, to develop achievable decarbonisation targets. High-integrity frameworks such as the Science Based Targets Initiative (SBTi)[1] provide guidance on areas such as the development of both cumulative and annual emission targets, with consideration of interim targets.

High-integrity targets align to the science of climate change, prioritising cumulative emissions targets or carbon budgets, a sum of allowable emissions over a time period aligned with a 1.5ºC or 2ºC pathway. Other forms of targets can also be used in conjunction with cumulative targets, including annual emissions, intensity, engagement and renewable energy targets as outlined below.

An individual mining operation within a broader asset or corporation may not have an individual target. These may be set at the group or corporate level. This requires apportionment across operations within the group on how the carbon budget may be equitably or strategically applied. The carbon budget may be split pro-rata according to the baseline year, giving each group member an equitable carbon budget. However, this approach may miss several key considerations, such as:

- **Greenfields projects:** Using baseline emissions for existing operations suggests new operations (not included in the baseline) will have a zero-carbon budget, or existing operations must forego some of their budget to account for new assets. Forward planning and consideration are required for new operations.
- **Operation closure:** Excessive carbon budget should not be given to operations that are expected to close within the target period.
- **Difficulty:** Some operations are hard to abate, and require technological and commercial innovation over a longer period. Greater budget should be apportioned to hard-to-abate operations, requiring action to be brought forward in other areas.
- **Mergers, divestments, and acquisitions:** Changing corporate structures requires a reassessment of the emissions baseline and available carbon budget. Divesting emission-intensive assets would also reduce the baseline (not just emissions), whereas acquisitions may increase the carbon budget but also increase the liability to decarbonise.

Target setting

There are a range of target types, each with its own set of criteria. Current best practice for decarbonisation is to set multiple long-term and short-term targets. This aligns with the SBTi methodology. Several interdependent types of targets are outlined below.

Cumulative emission targets

Cumulative emission targets refer to the total emissions added to the carbon cycle between a baseline year and the target year. A carbon budget represents the sum of all allowable emissions over the target period.

1 https://sciencebasedtargets.org

Annual emission targets (net zero)

The most common target currently is a net zero target, such that the net annual rate of emissions is zero tCO_2-e/y by a given year. An annual emissions target alone is insufficient, as it does not set a pathway. **Annual emissions targets should be paired with cumulative emissions targets and other targets to ensure a high-integrity, target-setting process and clearly demonstrate a pathway of reductions**. These can include Scope 1 and 2, but often higher-standard targets require the inclusion of Scope 3 emissions.

Figure 3 visualises the difference between cumulative and point-in-time emission targets.

Figure 3: Highlighting the difference between cumulative and annual emission targets. In both cases, net zero emissions by 2050 is achieved, but the bottom pathway has half as many cumulative emissions.

Until recently, SBTi focused on the cumulative emission targets. There is now a 'Net-Zero Standard' provided by the SBTi.[2] Because the annual rate of emissions is less relevant than the total carbon in the carbon cycle, there is greater scrutiny placed on net zero targets by the SBTi. Net zero is defined by the SBTi as:

"Companies shall set one or more targets to reach a state of net-zero emissions, which involves: (a) reducing their Scope 1, 2 and 3 emissions to zero or to a residual level that is consistent with reaching net-zero emissions at the global or sector level in eligible 1.5°C scenarios or sector pathways and; (b) neutralizing any residual emissions at the net-zero target date and any GHG emissions released into the atmosphere thereafter."

2 See https://sciencebasedtargets.org/resources/files/Net-Zero-Standard.pdf

Intensity targets

Unlike cumulative and annual emission targets, which target absolute emissions, intensity targets represent a rate of emissions per unit of production or consumption. For example, various commodities, ore types and bodies reflect a different energy intensity per tonne of saleable metal. Reducing intensities in production is a plausible target, but this is insufficient by itself.

Intensity targets should be coupled with annual emissions targets and cumulative targets to ensure climate action integrity. There are also various forms of intensity targets, ranging from economic intensity to relative sectoral intensities. These can include any scope of emission.

Engagement

Beyond Scope 1 and 2 targets, there are options for setting targets in collaboration with customers and suppliers to reduce Scope 3 emissions. Engaging up and down the value chain is required to reduce overall Scope 3 emissions.

Renewable electricity

As electricity is central to any decarbonisation pathway, there is often an ability to set interim and long-term electricity procurement targets. **Using both on-site generation and market instruments such as LGCs, electricity can be reliably decarbonised at an early stage**. For example, while the overall target might be 'Net zero by 2040', a secondary target of '100 per cent renewable electricity by 2030' may be included.

Step 3: Plan

With the zero-carbon target in mind, back-casting can be used to identify the technology solutions required to achieve this end-state. Techno-economic models can test various implementation scenarios against emissions targets and financial metrics, and determine the best approach to sequencing, including 'no-regrets' short-term actions. This is a decarbonisation pathway, which can be constructed in multiple forms and compared against other pathways to understand the impact of each on the ability to achieve the stated targets.

The decarbonisation pathway demonstrates the baseline emissions forecast, subtracting the emissions impact of each decarbonisation project. Projects can be mapped using the same tree structure in Step 1. Each activity is replaced or amended using different technologies and strategies so that the desired end-state and carbon budget is achieved.

Planning should avoid double counting of emissions and ensure projects are consistent, with each decarbonisation initiative referring directly to a line item or activity within the baseline forecast. Iteration is expected between planning and target setting, as the planning process may identify adjustments to targets.

Step 4: Implement

Very few organisations have fully implemented a decarbonisation plan. This is new territory for many mid-tier and junior miners, and rigor will be required to confidently navigate the transition.

Engagement with key stakeholders will help effectively manage the transition. Rigour and transparency in targets and implementation pathways will increase confidence with financiers and potential access to preferential ‘green’ finance solutions while supporting buy-in and understanding from operations teams that will implement and manage changes.

Considering production impacts will also be central to any implementation, and managing expectations on timelines and navigating technological uncertainty will separate successes from failures.

Step 5: Monitor

As the global decarbonisation journey matures, expected standards of monitoring and disclosure are increasing. As understanding of climate risk improves, so will the ability of board directors to manage and mitigate risk in line with their fiduciary duties. Utilising widely accepted disclosure frameworks such as the Taskforce on Climate Related Disclosures (TCFD) to guide reporting will support transparency and confidence in the roadmap and keep stakeholders engaged.

Setting and achieving interim targets will also provide confidence to stakeholders in the ability to decarbonise. Alternatively, failure to meet targets may lead to difficulty in sourcing capital, diminish social licence to operate, and make the business less competitive. From a mid-tier to junior company perspective, access to capital is critical, increasing the importance and potential of interim targets.

Project Zero

Project Zero illustrates the road mapping process and simulates the impact of four decarbonisation pathways on a hypothetical 'typical' existing copper mine and processing operation – 'Mine Zero'. The rationale for doing so is to provide mining companies with a practical guide to achieve zero-carbon mining while highlighting key considerations, risks, and opportunities. Project Zero demonstrates the usefulness of a scenario-based, techno-economic assessment approach for developing a robust asset decarbonisation roadmap. The specific context for Mine Zero was deliberately shaped to represent a hard-to-abate problem to practically highlight decarbonisation thinking in a complex setting.

Mine Zero is a mine-to-metal copper operation located in remote WA with a remaining mine life of 25 years. Key details of Mine Zero are provided in Table 1.

Table 1: Summary of key details for Mine Zero

Parameters	Mine Zero
Mine stage	Brownfield
Commodity mined	Copper
Mine location	Remote Western Australia
Grid connectivity	Off-grid
Energy sources	Natural gas: On-site power generation and thermal demand from processing Diesel: On-site equipment and material movement
Energy demand	1,486 GWh (43% electricity, 17% thermal, 40% diesel)
Annual material movements (tonnes)	50-65 Mtpa
Mining fleet	30–40 haul trucks, 5–10 excavators or loaders, 5–10 drills, 5–10 mining support vehicles
Annual GHG emissions	441 ktCO_2-e
Remaining life of mine	25 years, from 2025
Financial assumptions	Weighted Average Cost of Capital (WACC) of 7%. All dollar values are 2021 Australian dollars unless stated otherwise. Average carbon price of $50[3] per t$CO_2$-e as a modelling assumption. This could reflect an internal company policy, a shadow price of regulatory requirements or a direct regulatory requirement.
Mining operations on site	Mine-to-metal, including in-mine equipment (drilling and blasting, loading, haulage, and ancillary operations such as service and water trucks), concentrator (crushing and grinding, flotation and separation), smelting, refining (electrolysis) and material movement

3 All references to $ refer to the Australian Dollar (AUD).

The energy value chain

The energy value chain of Mine Zero in the BaU case is dominated by fossil fuels – natural gas and diesel. Diesel consumption supplies all the energy demand from in-mine equipment and mobility, which includes haulage and road trucks. Natural gas supplies the thermal demand from energy-intensive processes such as smelting and refining. All the electricity demand of Mine Zero is supplied through natural gas powered reciprocating engines. The energy value chain for Mine Zero is shown in Figure 4.

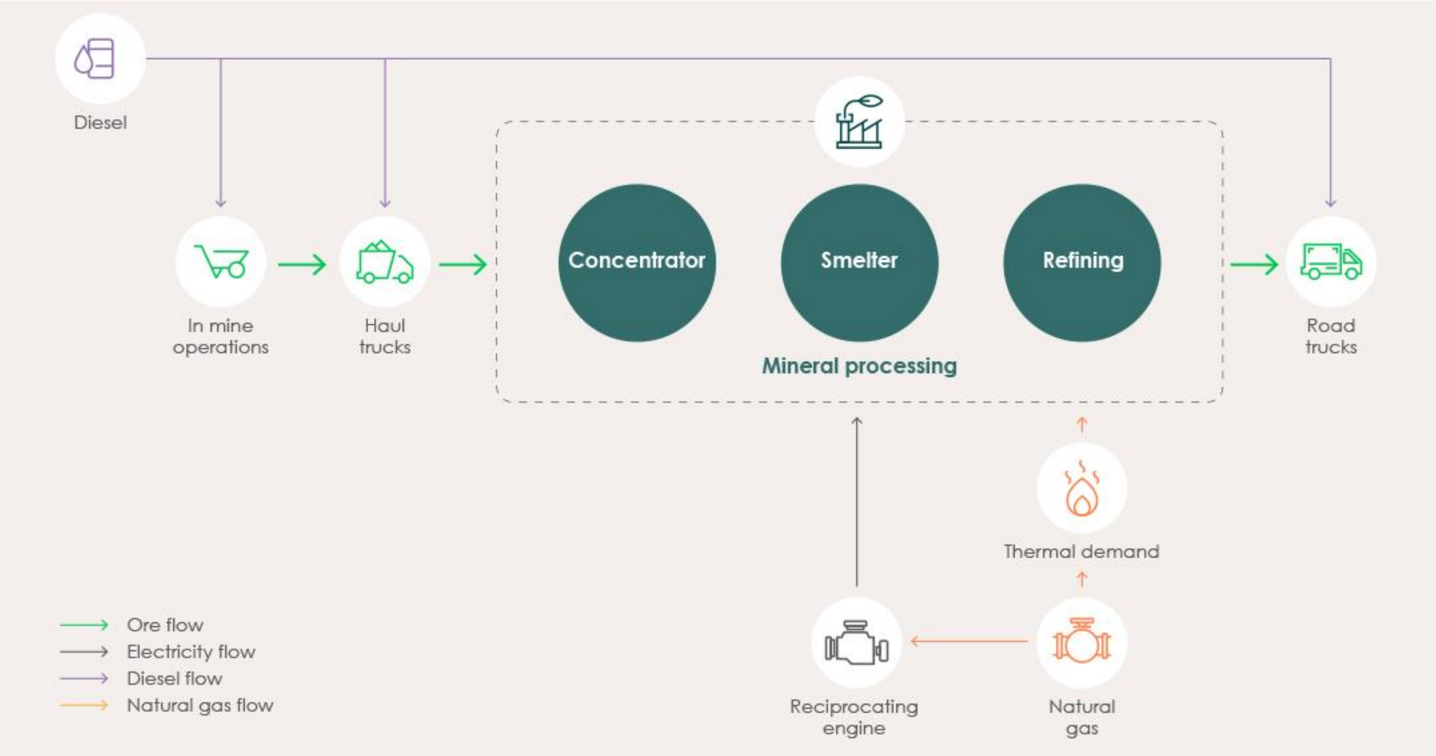

Figure 4: Mine Zero's initial BaU energy value chain

Energy and emissions profile

Energy demand and its allocation across key operations at Mine Zero was based on available data from copper mines globally. An energy baseline representing the breakdown of energy demand across these key operations is presented in Figure 5. The total annual energy demand for the mine (end-use) is 1,486 GWh/y. Electricity generation from natural gas makes up 43 per cent. Diesel accounts for 40 per cent. Heating processes for refining account for the remaining 17 per cent.

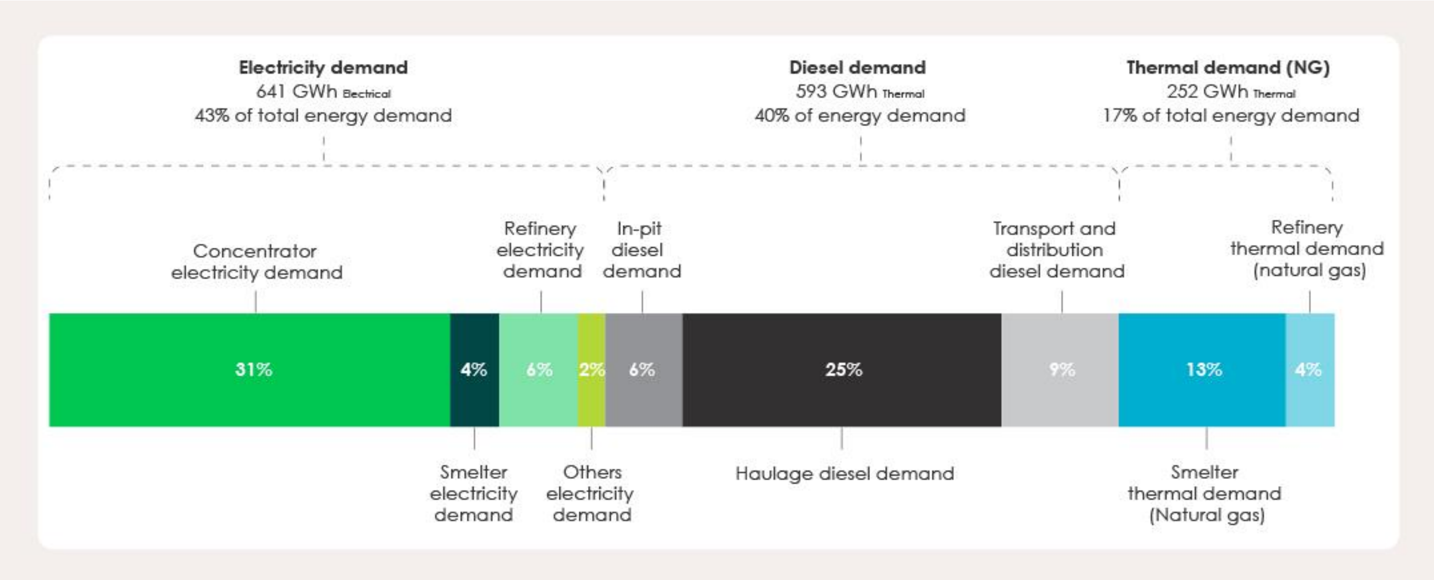

Figure 5: Mine Zero's baseline energy consumption breakdown, based on the year with the highest energy demand, 2037

The original, unabated greenhouse gas (GHG) emissions profile and trajectory for the life of Mine Zero is provided in Figure 6. The total annual emissions of Mine Zero were estimated to be 441 ktCO_2-e in Year 1. Combustion of natural gas for electricity generation accounts for roughly 70 per cent of baseline emissions. Diesel combustion makes up 14 per cent. Natural gas consumption for thermal processes accounts for 10 per cent. Emissions are projected to peak in 2037 owing to the increased diesel demand from haulage trucks.

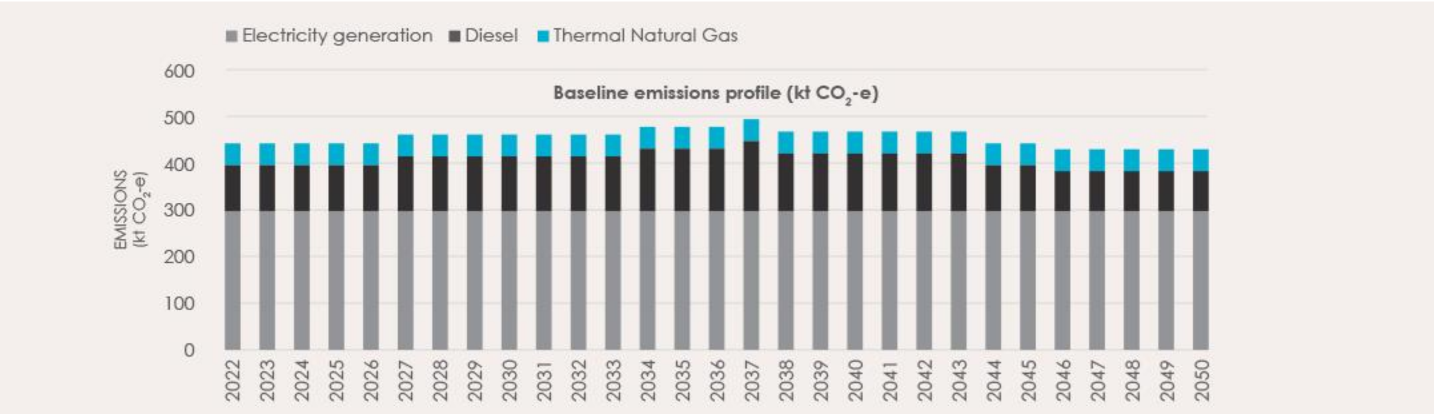

Figure 6: Mine Zero's baseline emissions trajectory

Decarbonisation pathways

Four decarbonisation pathways were developed to represent realistic options to decarbonise Mine Zero (Table 2). Pathways were deliberately thematic to showcase a breadth of technologies in the assessment. Each pathway represents a combination of the decarbonisation technologies illustrated in *Mining in a low-emissions economy: Technology Solutions for Decarbonisation.* The phasing and sequencing for implementation of technologies across the life of Mine Zero were developed into an implementation plan.

Implementation was separated in to three distinct phases aligning with short-term, medium-term, and long-term time horizons:

– **Phase 1 (in effect 2025–2050):** This 'no-regrets' phase of implementation represents low-risk capital investment in commercially mature decarbonisation technologies common across pathways, with renewable energy found to fit these goals. The focus is on immediate quick wins with strong economics that form the foundation for achieving zero-carbon mining while leaving options open for competing emerging technologies.

– **Phase 2 (in effect 2030–2050):** The intermediate phase builds on Phase 1 with technology investments into emerging technologies that are specific to each pathway, for example, to decarbonise thermal demand and in-mine equipment. These capital investments must be strategically deployed targeting the displacement (in-part or whole) of fossil fuels used for thermal processes and/or mobility.

– **Phase 3 (in effect 2035–2050):** The endgame is the final capital investment phase that addresses the most difficult sources of emissions to decarbonise, such as material movement. Investment is in pathway-specific technologies or in the purchase of market-based solutions such as carbon instruments that are in line with the company's environmental, social and governance (ESG) strategy.

The timeline for phasing considered the commercial maturity of decarbonisation options and aligned with a typical 5-year investment cycle for a mine. For our modelling, we assumed that these investments (for each phase) will occur at the start of each phase. Each phase is assumed to implement the technology options entirely in the year prior to the first year of the phase and remain in place for the lifetime of the mining operation (e.g. the implementation in 2024 for Phase 1 to be in effect 2025–2050).

The Mine Zero operator aims to achieve zero-carbon emissions by 2040, at the latest. In line with other mining companies, the business has ambitious decarbonisation goals and has chosen a deadline sooner than most policy or regulatory mandates. It is also practical that the business aims to achieve net zero before the mine's expected end of life in 2050. Another factor influencing the 2040 target was that the technologies under consideration are expected to be mature and costs are expected to begin to plateau by 2040.

Table 2: Overview of decarbonisation pathways considered for Mine Zero

	Pathway 0 Business-as-Usual	Pathway 1 Established Technology	Pathway 2 Electrification	Pathway 3 Hydrogen Importer	Pathway 4 Hydrogen Producer
Targets	NA	Achieve net zero carbon emissions by 2040	Achieve zero carbon emissions by 2040		
Technology Risk Profile	Low	Low	Medium	High	High
Electricity Generation Options	Continued use of natural gas for electricity generation	Solar and Wind	Solar, wind, concentrated solar with thermal storage, pumped hydro, e-fuel (imported green hydrogen or green ammonia)	Solar, wind, concentrated solar with thermal storage, pumped hydro and e-fuel (imported green ammonia)	Solar, wind, concentrated solar with thermal storage, pumped hydro, e-fuel (green hydrogen produced on site)
Energy Storage Options	NA	Li-ion batteries for short-term storage	Li-ion, vanadium flow and sodium-sulphur for short-term storage	Li-ion, vanadium flow and sodium-sulphur for short-term storage; imported green ammonia as proxy for seasonal storage	Li-ion, vanadium flow and sodium-sulphur for short-term storage; green hydrogen for seasonal storage
Thermal Demand	Continued use of natural gas to meet thermal need	Electrification of thermal demand will be evaluated	Electrification of thermal demand	Green ammonia	Electrification or green hydrogen for thermal demand will be evaluated
Mobility	Continued use of diesel fuel to power all mobility needs	Electrified in-mine equipment and diesel or biofuels for haulage fleet	Electrified in-mine equipment and haulage fleet	Green ammonia powered in-mine equipment and haulage fleet	Electrification of in-mine equipment and green hydrogen powered long-haul fleet
Market-based Solutions	None	Reliance on offsets	Offsets only in the short-term, by 2040 emissions are brought down to zero	Offsets only in the short-term, by 2040 emissions are brought down to zero	Offsets only in the short-term, by 2040 emissions are brought down to zero

Modelling approach

Scenario-based, techno-economic assessment was used to determine the least-cost technical solution for each pathway

Modelling of decarbonisation pathways for the mine leveraged Prosumer, an intuitive decarbonisation simulation tool developed by ENGIE for undertaking scenario-based, techno-economic assessments to guide decarbonisation roadmap development. Prosumer was tailored and launched to the mining industry in 2021 and has been used on 16 mines to develop decarbonisation roadmaps targeting zero-carbon mining. The software draws on the technology insights from ENGIE's research and development to optimise sizing and costs for the endgame solution for each pathway (Figure 7). Back-casting is used to establish the optimal phasing of capital investment and rollout of infrastructure. Implementation is aligned with the short, medium, and long-term decarbonisation goals set by the business.

Five key steps were taken to develop the decarbonisation roadmap for Mine Zero:

1. Develop an energy and emissions baseline and BAU trajectory for the life of the mine.
2. Determine the decarbonisation ambition for Mine Zero.
3. Construct four decarbonisation pathways.
4. Model the four decarbonisation pathways using Prosumer.
5. Build the decarbonisation roadmap including the phasing and sequencing to implement solutions.

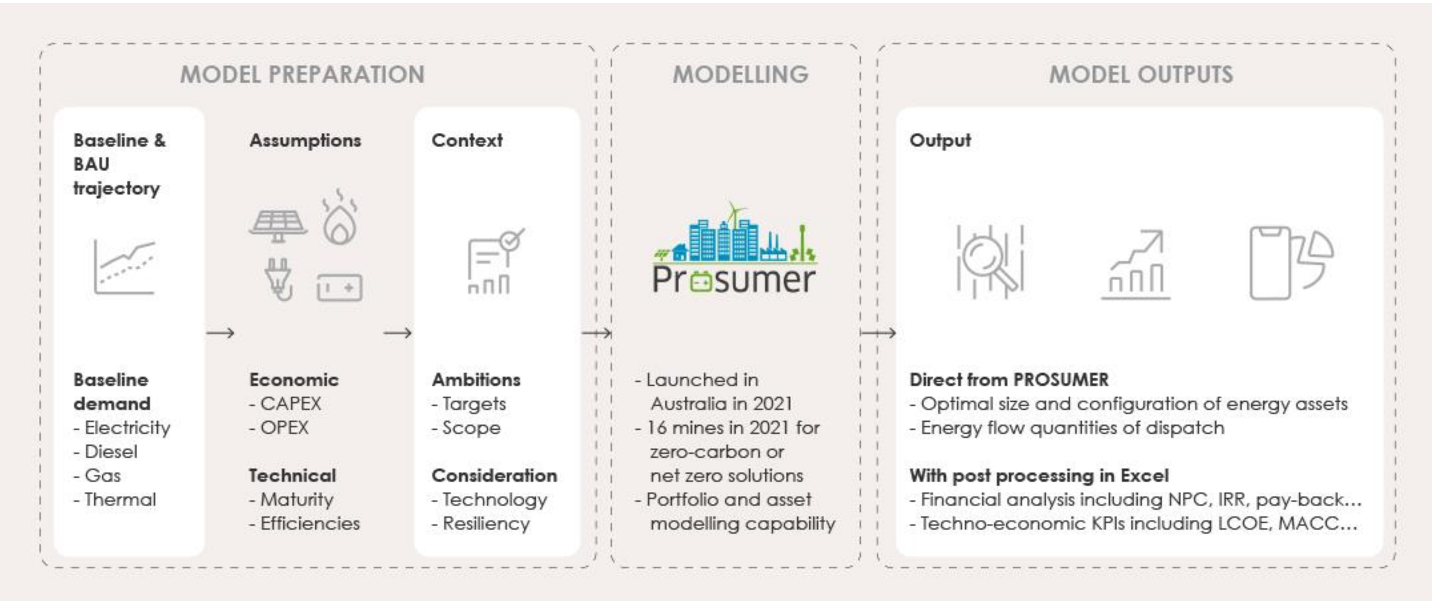

Figure 7: Key input and outputs required for Prosumer modelling

Pathway 1: Established Technology

Low technology risk. Relying on technology that has reached technical and commercial maturity with carbon offsets for residual emissions.

The energy value chain, in the Established Technology pathway in the final state, prioritises on-site renewable electricity generation through on-site solar and wind installations supplemented by natural gas powered gensets and battery systems. Thermal demand from the processing plant and energy demand from in-mine equipment will be electrified, while diesel will remain in the energy mix to cater to the mobility demand from haulage systems and road trucks. Carbon offsets will be purchased as required to reach a net-zero-carbon system in 2040. The energy value chain for the Established Technology pathway is shown in Figure 8.

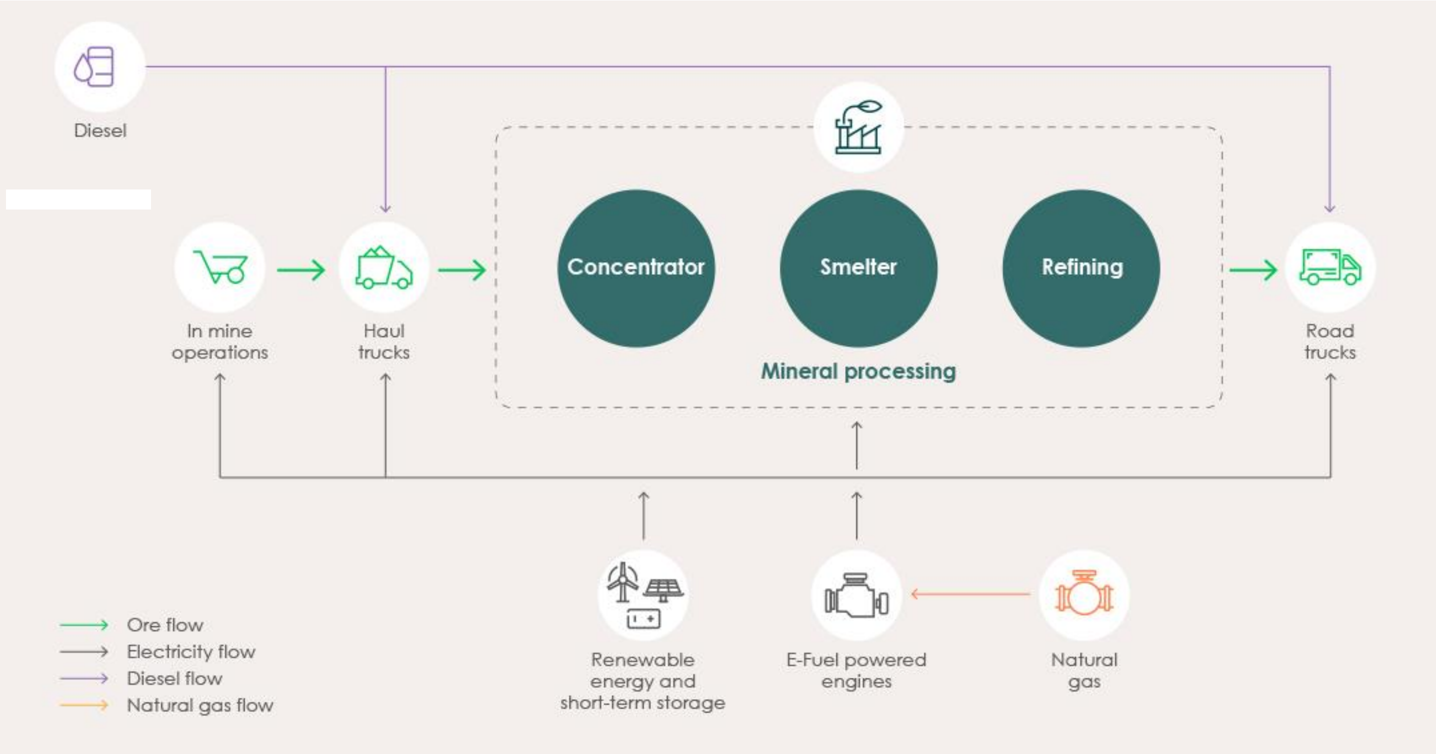

Figure 8: Energy value chain of the Established Technology pathway in 2040

Phasing of decarbonisation projects in the Established Technology pathway is driven primarily by the technological and commercial maturity of solutions. Phase 1 targets a renewable penetration of ~70 per cent through on-site solar PV and wind installations by 2025. This is a common step for all pathways. Phase 1 achieves a ~46 per cent reduction in carbon footprint resulting from reduced natural gas usage for electricity generation, predominantly used for mineral processing.

Phase 2 in this pathway displaces natural gas catering to the thermal demand from the process plant through electrification. This is achieved through additional on-site renewable installations, natural gas powered gensets, and the introduction of battery systems.

Phase 3 displaces diesel powered in-mine equipment with electrified alternatives. The resulting increase in electricity demand will be supplied by additional on-site renewable and battery installations. Residual fossil fuels in the energy system include natural gas for electricity generation, and the diesel demand from haulage and road trucks.

Carbon offsets are required to offset residual emissions that exist from fossil fuel usage. The quantity of offsets required to achieve a zero-carbon mine must continue to be purchased to match annual residual emissions.

A detailed breakdown of the implementation phases for Established Technology is shown in Table 3. The annual emissions avoided are shown in Figure 9.

Table 3: Pathway 1 phase breakdown

	Phase 1	Phase 2	Phase 3
Timing	Implementation year: 2024 In effect: 2025–2050	Implementation year: 2029 In effect: 2030–2050	Implementation year: 2034 In effect: 2035–2050
On-site renewables capacity	Installation of on-site renewables: – Solar PV capacity of 71 MW. – Wind energy capacity of 92 MW.	Increasing on-site renewables capacity: – Additional solar PV capacity of 85 MW. Total solar PV capacity = 156 MW. – Wind energy capacity of 66 MW. Total wind capacity = 158 MW.	Increased on-site renewables capacity: – Solar PV capacity of 16 MW. Total solar PV capacity = 172 MW.
Installation of short-term storage	No short-term storage	Li-ion battery of 95 MW/379 MWh	Additional Li-ion battery of 25 MW/99 MWh
Fuel imports	– Diesel for mobility and in-mine equipment. – Natural gas for thermal demand and on-site electricity generation.	– Diesel for mobility and in-mine equipment. – Natural gas for electricity generation.	– Diesel for mobility. – Natural gas for electricity generation.
Summary	– No-regrets capital investments into on-site renewables to partially decarbonise processing plant electricity demand.	– Build on phase 1 capital investments to increase on-site renewables. – Electrification of thermal demand from process plant. – Continued use of diesel for haul trucks, road transport, and in-mine equipment.	– Building on phase 2 renewable installations to cost-effectively decarbonise electricity-related emissions. – Electrify in-mine equipment. – Continued use of diesel for haulage trucks and road trucks.
Market-based solutions	Offsets to meet short-term emissions reduction targets (if any).	Offsets to meet mid-term emissions reduction targets (if any)	Offsets to meet zero carbon
CAPEX Requirement by phase	$317m	$377m	$50m
Internal Rate of Return vs BaU (over mine life)	26%	19% (phase 1 and 2)	18% (phase 1, 2 and 3)

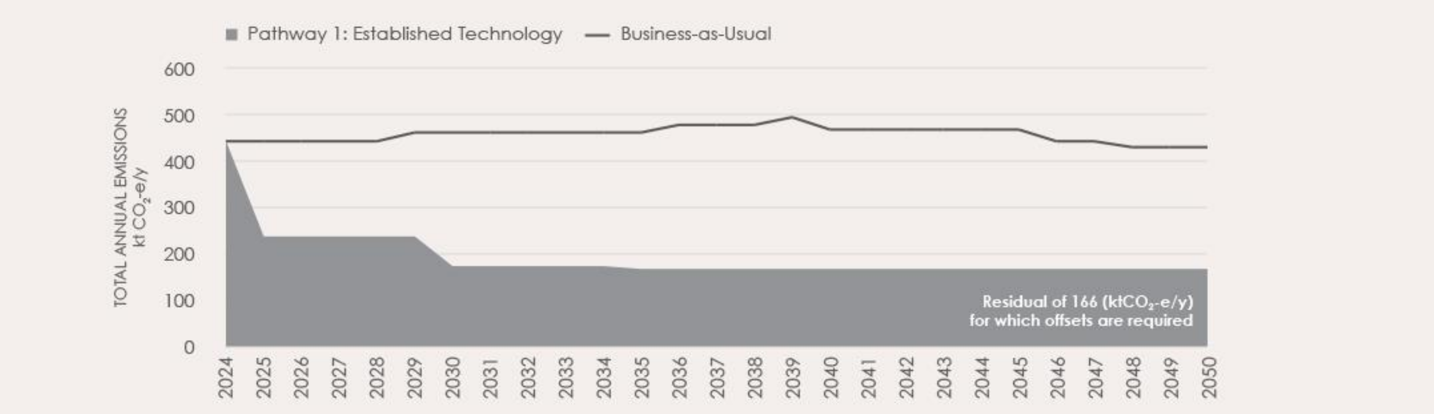

Figure 9: Emissions avoided compared to BaU for the Established Technology pathway

The total capital expenditure (CAPEX) required for this pathway is $744 million. A breakdown of the CAPEX investment across each of the three implementation phases is shown in Figure 10. An initial capital investment of $317 million is required by 2025 to execute Phase 1. Electrification of thermal demand, increased wind and solar capacity and the inclusion of battery storage will require an additional $377 million capital investment in Phase 2. This investment is expected by 2029–30. Phase 3, which does not reach zero carbon, requires significantly less capital investment than the previous two phases. The investment for Phase 3 is required by 2035 and Mine Zero will require the ongoing purchase of carbon offsets for residual emissions. The reliance on carbon offsets exposes the asset to greater carbon pricing and emissions regulation risks compared to the other three pathways.

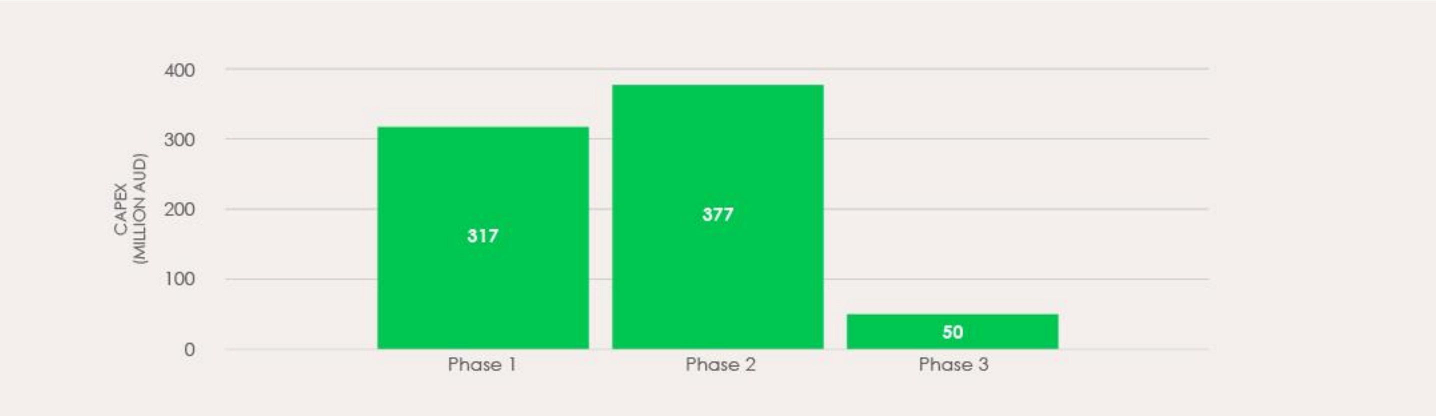

Figure 10: Phased CAPEX of Pathway 1

Emissions reductions of 205 ktCO_2-e are achieved through Phase 1 (Figure 11). Electrification of thermal demand further reduces emissions by 64 ktCO_2-e in Phase 2. Electrification of in-mine equipment in Phase 3 has a relatively small impact on Mine Zero's total emissions (6 ktCO_2-e). Mine Zero will have residual emissions of approximately 166 ktCO_2-e. These emissions are attributed to the use of diesel in haul trucks and road trucks and natural gas combusted for electricity generation.

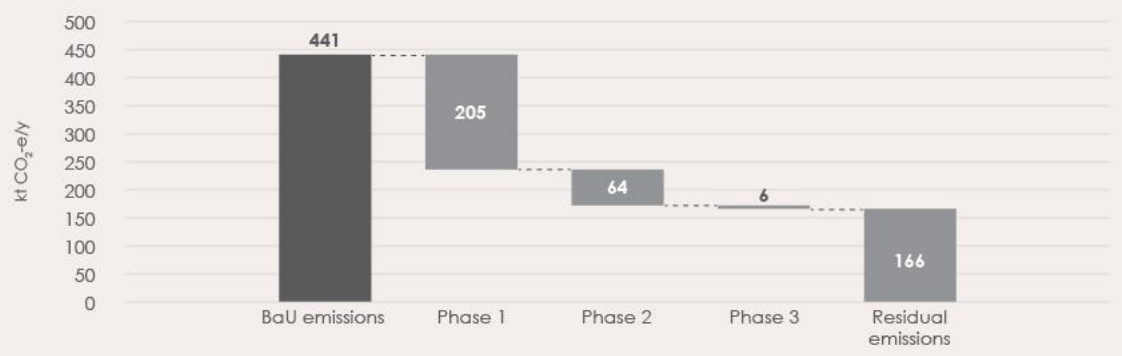

Figure 11: Annualised emissions reduction per phase in Pathway 1 (ktCO_2-e)

In addition to the emission savings achieved through the capital investments into decarbonisation technologies, these capital investments result in cost savings from avoided operating expenditure (OPEX), specifically avoided fuel expenditure, compared to the BaU pathway. The difference in the discounted net-present costs – calculated over a 25-year horizon – between the Established Technology pathway and the BaU costs (excluding any costs of carbon) is shown in Figure 12. Cost savings of $588 million are expected from avoided fuel expenditure.

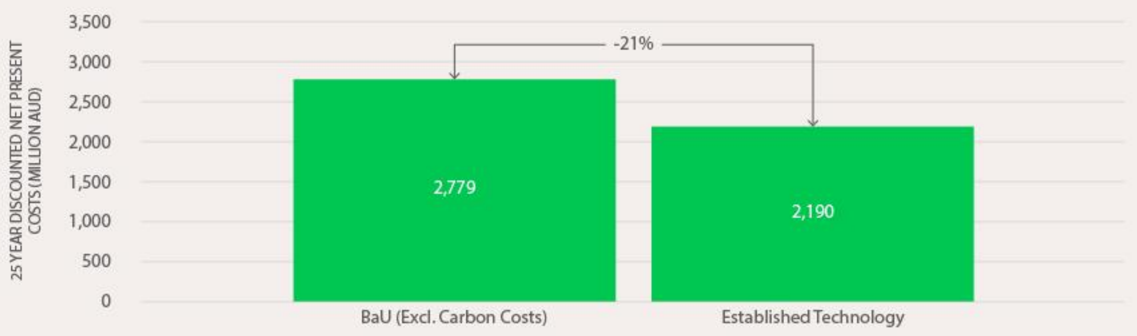

Figure 12: Savings compared to the BaU for the Established Technology pathway

The economics depict a favourable outcome for investment in decarbonisation projects for the Established Technology pathway. The following financial metrics further highlight the attractiveness of the capital investments into decarbonisation projects:

- **Payback period:** This indicator represents the time elapsed, in years, for the Established Technology pathway capital investments to reach cost parity with BaU energy costs. This is illustrated by the intersection of the net-present energy cost curves for the Established Technology pathway and BaU case (Figure 13). These cost curves include both the CAPEX and the OPEX. Cost savings from avoided fuel expenditure are realised beyond the point of cumulative net present costs crossover. For the Established Technology pathway, the cost curves indicate that financial payback for the decarbonisation projects is achieved by 2034. The inclusion of a carbon price (averaging $50 per tCO_2-e) brings the payback period forward to 2032.

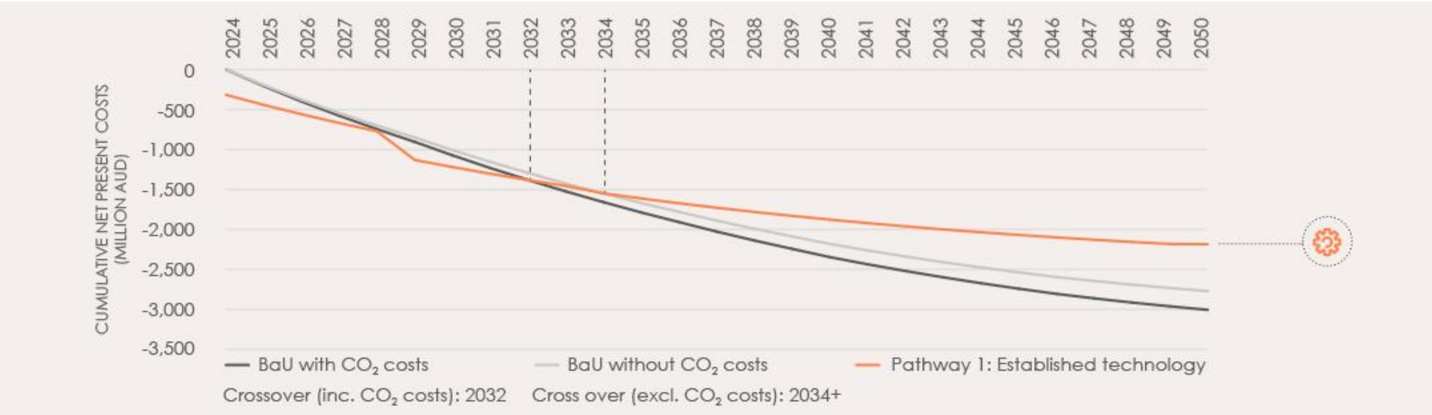

Figure 13: Established Technology vs BaU net-present energy costs

- **Internal Rate of Return (IRR)**: The capital investment in decarbonisation projects in the Established Technology pathway will result in savings compared to BaU. The investments and savings over the 25-year horizon were considered to calculate the rate of return on investments. The Established Technology pathway has an IRR[4] of 19 per cent (23 per cent with carbon price), which is higher than the weighted average cost of capital (WACC[5]) of 7 per cent. This indicates a favourable business case for the Established Technology pathway.

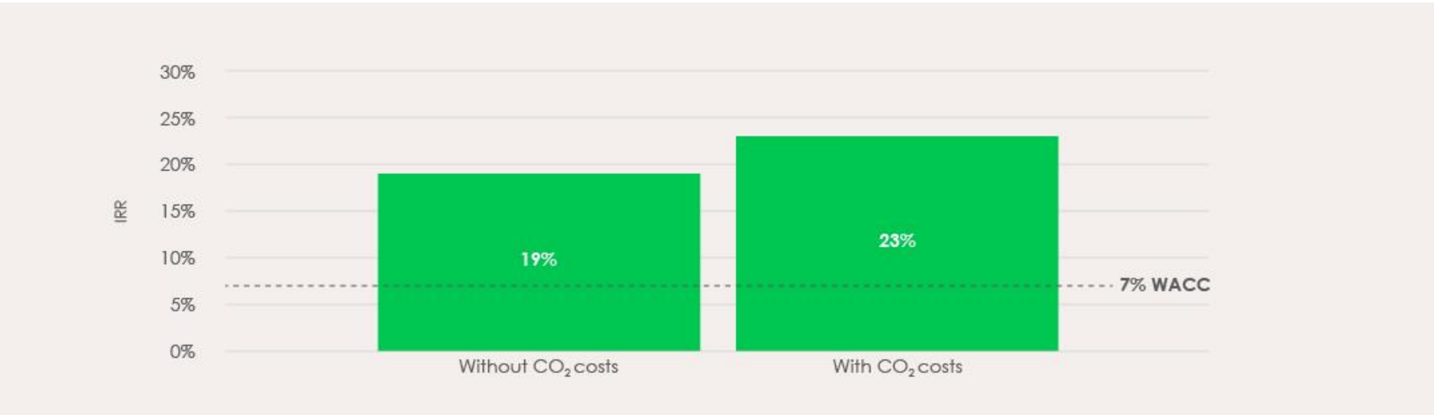

Figure 14: Established Technology pathway internal rate of return

Key outputs from the assessment of the Established Technology pathway are presented alongside the BaU in the Table 4.

4 Internal rate of return – is a method for calculating an investment's rate of return.

5 WACC – Weighted Average Cost of Capital is the rate that a company is expected to pay on average to all its security holders to finance its assets.

Table 4: Outputs of the Established Technology pathway

Parameters	Business as usual	Pathway 1: Established Technology
Target year for zero carbon	NA	2040
Net present costs (Millions of AUD)	\$2,779 (no carbon costs) \$3,013 (with carbon costs)	\$2,190
Total annual system emissions (ktCO_2-e)	~441 ktCO_2-e	~166 ktCO_2-e
IRR	NA	19% (vs BaU without carbon costs) 23% (vs BaU including carbon costs)
Time to reach cost parity (years)	NA	10 years (vs BaU without carbon costs) ~8.5 years (BaU including carbon costs)

Pathway 2: Electrification

An electricity-centric pathway that aims to achieve zero carbon by utilising direct and indirect electrification strategies where possible.

The Electrification pathway explores electrifying energy demand where possible. The energy system for this pathway prioritises on-site renewable electricity generation through solar PV and wind installations, supplemented by e-fuel powered gensets and battery systems. E-fuels are a liquid or gas fuel that is produced using energy from electricity. Green hydrogen is produced from electrolysis with renewable electricity, and green ammonia is produced from green hydrogen. Thermal demand from the processing plant (predominantly from the smelter and the refinery) will be directly electrified, as will energy demand from mobility and in-mine equipment (Figure 15). Increased efficiency of electrified mobility reduces the energy demand significantly and therefore operating costs.

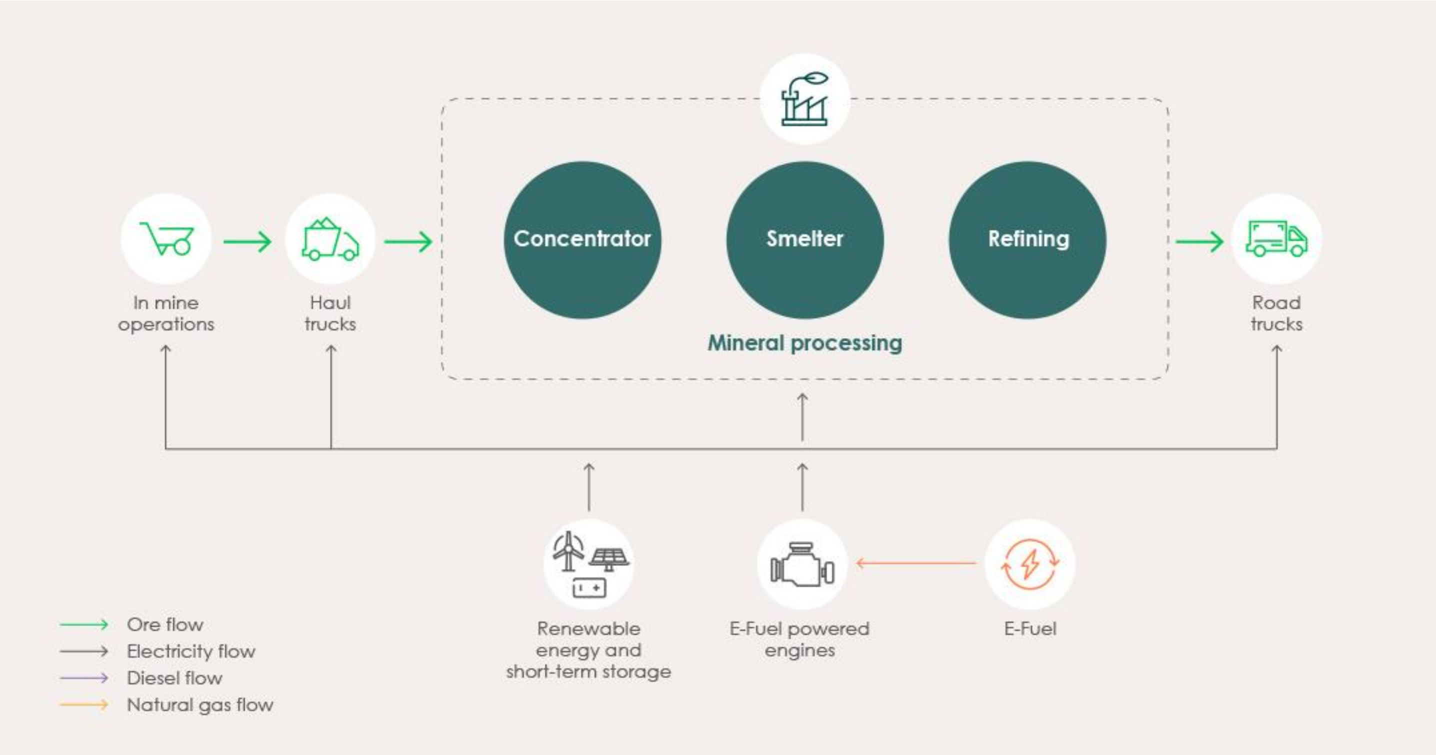

Figure 15: Energy value chain of the Electrification pathway in 2040

Phase 1 is common for all pathways and is detailed in the Established Technology scenario description.

Phase 2 of the Electrification pathway focuses on electrifying thermal demand and in-mine equipment. Additional on-site renewable installations and the introduction of battery systems are the key capital investment. Diesel will continue to meet the mobility demand from haulage and road trucks until Phase 3.

Phase 3 focuses on displacing the remaining fossil fuels in the energy mix. The mobility demand will be electrified in addition to e-fuel imports to replace natural gas used for electricity generation. The increased electricity demand is met with additional renewables and battery system installations. The e-fuel powered gensets will provide a reliable firming capacity on-site.

The detailed breakdown of the phases can be seen in Table 5. Implementation of all three phases of the Electrification pathway will see Mine Zero reach zero carbon emissions by 2035 (Figure 16).

Table 5: Electrification pathway phase breakdown

	Phase 1	Phase 2	Phase 3
Implementation date	Implementation year: 2024 In effect: 2025–2050	Implementation year: 2029 In effect: 2030–2050	Implementation year: 2034 In effect: 2035–2050
On-site renewables capacity	Installation of on-site renewables: – Solar PV capacity of 71 MW. – Wind energy capacity of 92 MW.	Increasing on-site renewables capacity: – Additional solar PV capacity of 84 MW. Total solar PV capacity = 155 MW. – Wind energy capacity of 76 MW. Total wind capacity = 168 MW.	Increased on-site renewables capacity: – Additional solar PV capacity of 124 MW. Total solar PV capacity = 279 MW. – Wind energy capacity 23 MW. Total wind capacity = 191 MW.
Installation of short-term storage	No short-term storage	Li-ion battery of 109 MW/436 MWh	Additional Li-ion battery of 120 MW/480 MWh
Fuel imports	– Diesel for mobility and in-mine equipment. – Natural gas for on-site electricity generation and thermal demand.	– Diesel for mobility. – Natural gas for electricity generation.	Green ammonia for electricity generation
Summary	– No-regrets capital investments into on-site renewables to partially decarbonise processing plant electricity demand.	– Build on no-regrets capital investments to increase on-site renewables. – Electrification of process plant's thermal demand. – Electrified in-mine equipment. – Diesel for haul trucks and road transport.	– Increased on-site renewables and storage with imports of green ammonia for firming capacity. – Electrification of haul trucks and road trucks. – Electrification of process plant's thermal demand. – Electrified in-mine equipment.
Market-based solutions	Offsets to meet short-term emissions reduction targets (if any)	Offsets to meet mid-term emissions reduction targets (if any)	Not required
CAPEX Requirement by phase	\$317m	\$410m	\$345m
Internal Rate of Return vs BaU (over mine life)	26%	20% (phase 1 and 2)	20% (phase 1, 2, 3)

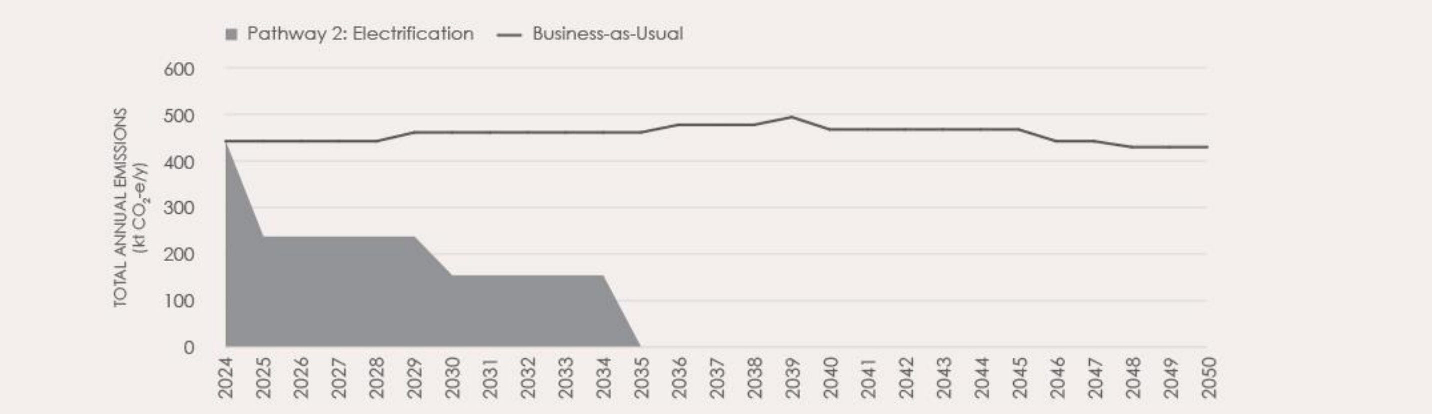

Figure 16: Emissions avoided compared to BaU for the Electrification pathway

The total CAPEX for this pathway across the three implementation phases is $1,072 million (Figure 17). The initial CAPEX for Phase 1 is $317 million by 2025. The intermediate phase will require further CAPEX of $410 million for additional renewables and battery systems by 2030. By 2035, Phase 3 will require another $345 million capital investment in on-site renewables to complete decarbonisation.

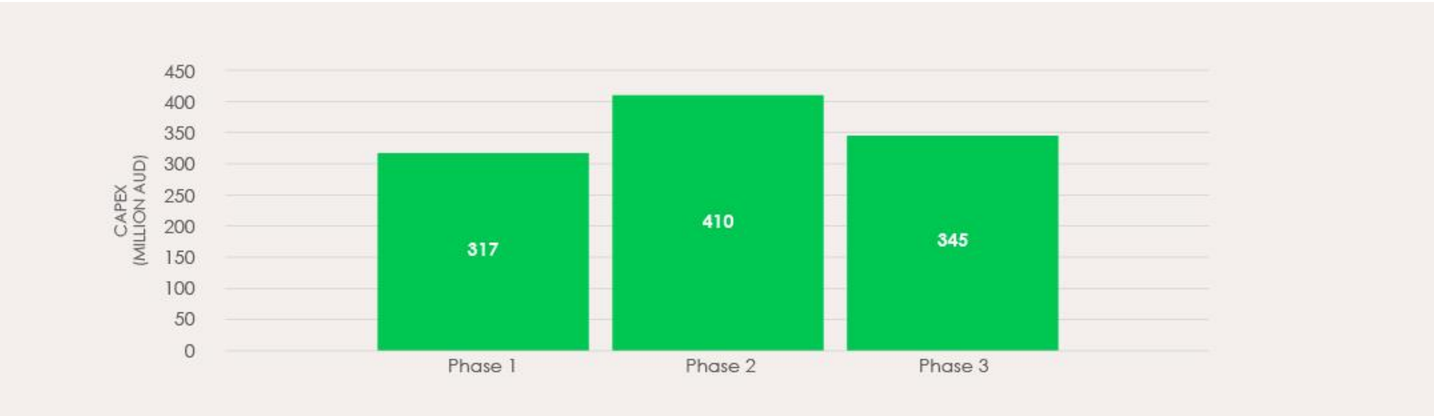

Figure 17: Phased CAPEX of Pathway 2

Figure 18 depicts the emissions reductions achieved across each phase. Phase 1 reduces emissions by 205 ktCO_2-e. Electrification of thermal demand and in-mine equipment in Phase 2 will reduce emissions by 83 ktCO_2-e. Lastly, in Phase 3, electrification of mobility and electricity generation fuelled by green ammonia allows for Mine Zero to reach zero carbon, achieving a 153 ktCO_2-e reduction.

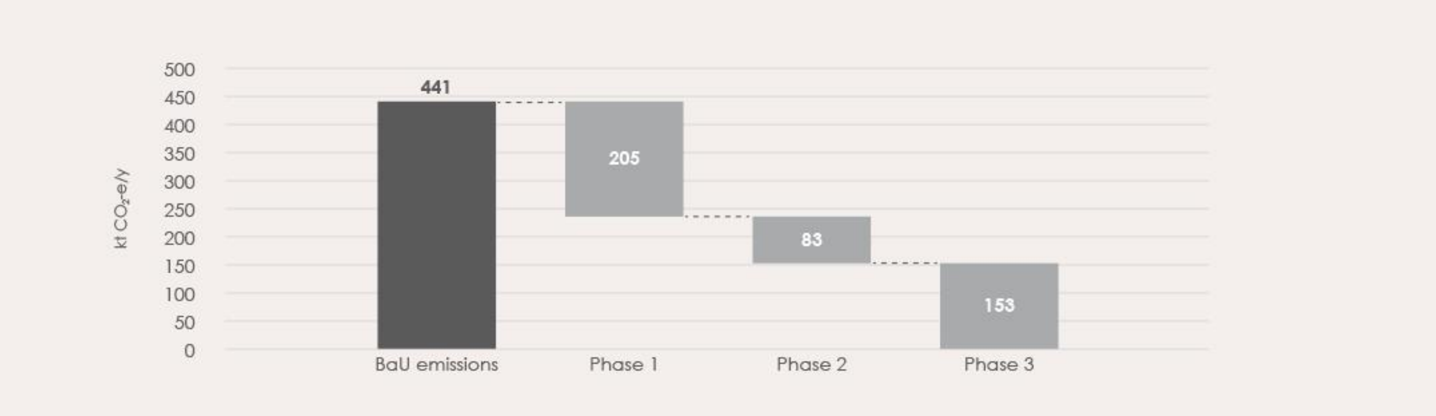

Figure 18: Annualised emissions reduction per phase in Pathway 2 (ktCO_2-e)

The pathway provides cost savings from both avoided fuel expenditure and efficiency gains from electrified mobility, compared to the BaU pathway. Over a 25-year horizon, $940 million, in potential savings are projected compared to BaU or a 34 per cent reduction (Figure 19).

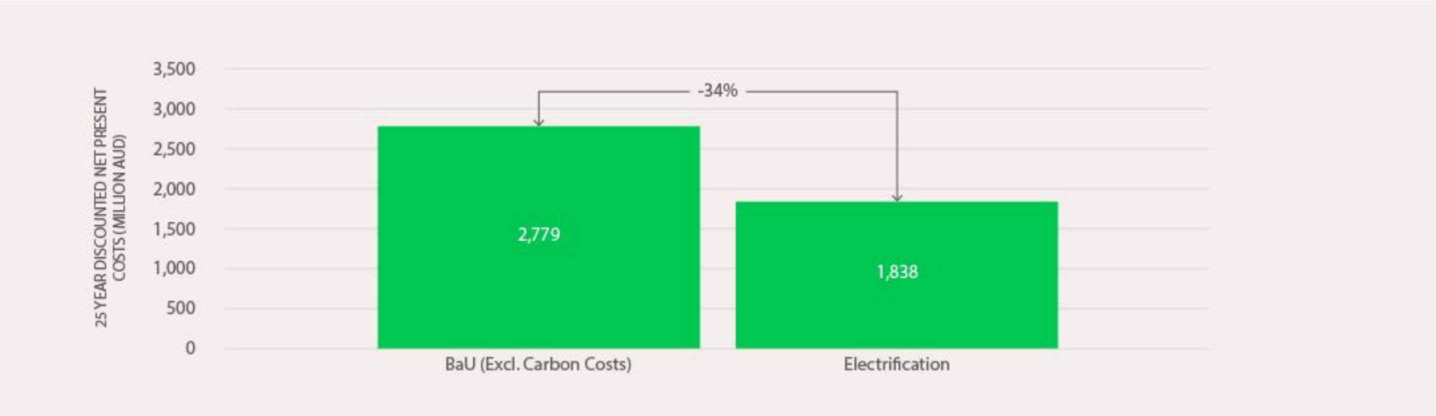

Figure 19: Savings from the Electrification pathway

In addition to the savings achieved, other financial metrics – such as the payback period and the IRR – support the capital investments in decarbonisation projects:

- **Payback period:** This indicator represents the time elapsed, in years, for the Electrification pathway capital investments to reach cost parity with BaU energy costs. This is illustrated by intersection of the net-present energy cost curves for the Electrification pathway and BaU case (Figure 20). These cost curves include both the CAPEX required and the OPEX. Cost savings from avoided fuel expenditure are realised beyond the point of cumulative net present costs crossover. For the Electrification pathway, the cost curves indicate that financial payback for the decarbonisation projects is achieved by 2035. Including a carbon price (averaging $50 per tCO_2-e) accelerates the payback period to 2031.

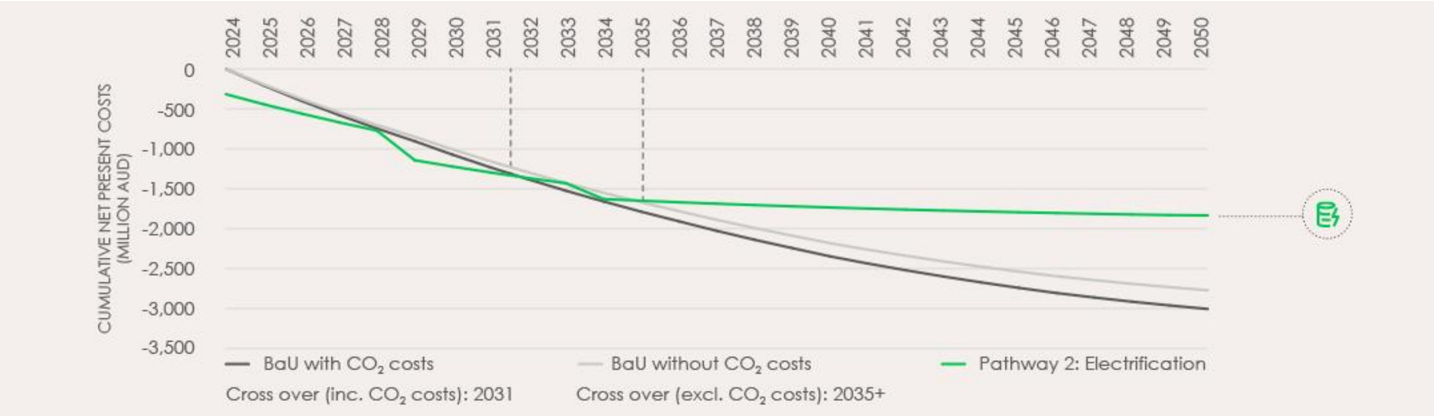

Figure 20: Pathway 2 net present cost comparison

- **IRR**: The capital investment in decarbonisation projects in the Electrification pathway will result in savings compared to BaU. The investments and savings over the 25-year horizon were considered to calculate the rate of return on investments. The Electrification pathway has an IRR of 20 per cent (24 per cent with carbon price), which is higher than the WACC of 7 per cent. This indicates a very strong business case for the Electrification pathway compared to other pathways.

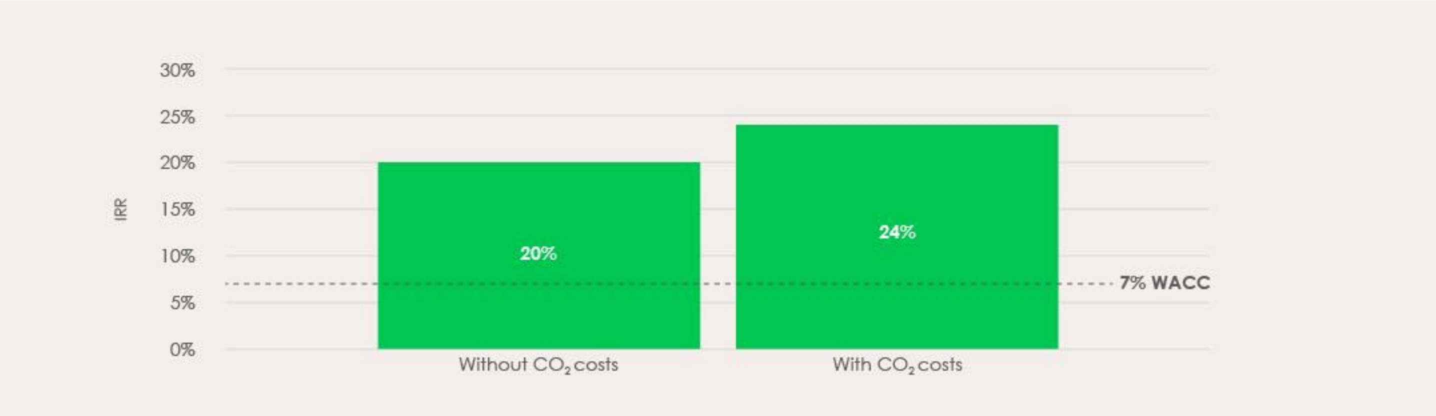

Figure 21: Pathway 2 internal rate of return

Key results from the Electrification pathway are presented in Table 6 below.

Table 6: Outputs from the Electrification pathway

Parameters	Business as usual	Pathway 2: Electrification
Target year for zero carbon	NA	2040
Net present costs (Millions of AUD)	\$2,779 (no carbon costs) \$3,013 (with carbon costs)	\$1,838
Total annual system emissions (ktCO_2-e)	~441 ktCO_2-e	0 ktCO_2-e
IRR	NA	20% (vs BaU without carbon costs) 24% (vs BaU including carbon costs)
Time to reach cost parity (years)	NA	11 years (vs BaU without carbon costs) ~8 years (BaU including carbon costs)

Pathway 3: Hydrogen Importer

Hydrogen Importer is a hydrogen-centric pathway that relies on indirect electrification (through the import of e-fuels) for thermal processes and mobility.

In the Hydrogen Importer pathway, indirect electrification through e-fuels such as green hydrogen, displace fossil fuels to meet Mine Zero's energy demand. The energy system of Hydrogen Importer consists of on-site renewables for electricity generation supplemented by e-fuel powered gensets and battery systems. The pathway also explores the impact of using imported e-fuels to cater to the thermal demand and the mobility demand from haulage and road trucks to achieve zero-carbon mining.

The value chain of the Hydrogen Importer pathway is shown in Figure 22. Since the pathway relies on e-fuel imports, the overall pathway requires lower capital investments but implies a higher overall operational expenditure.

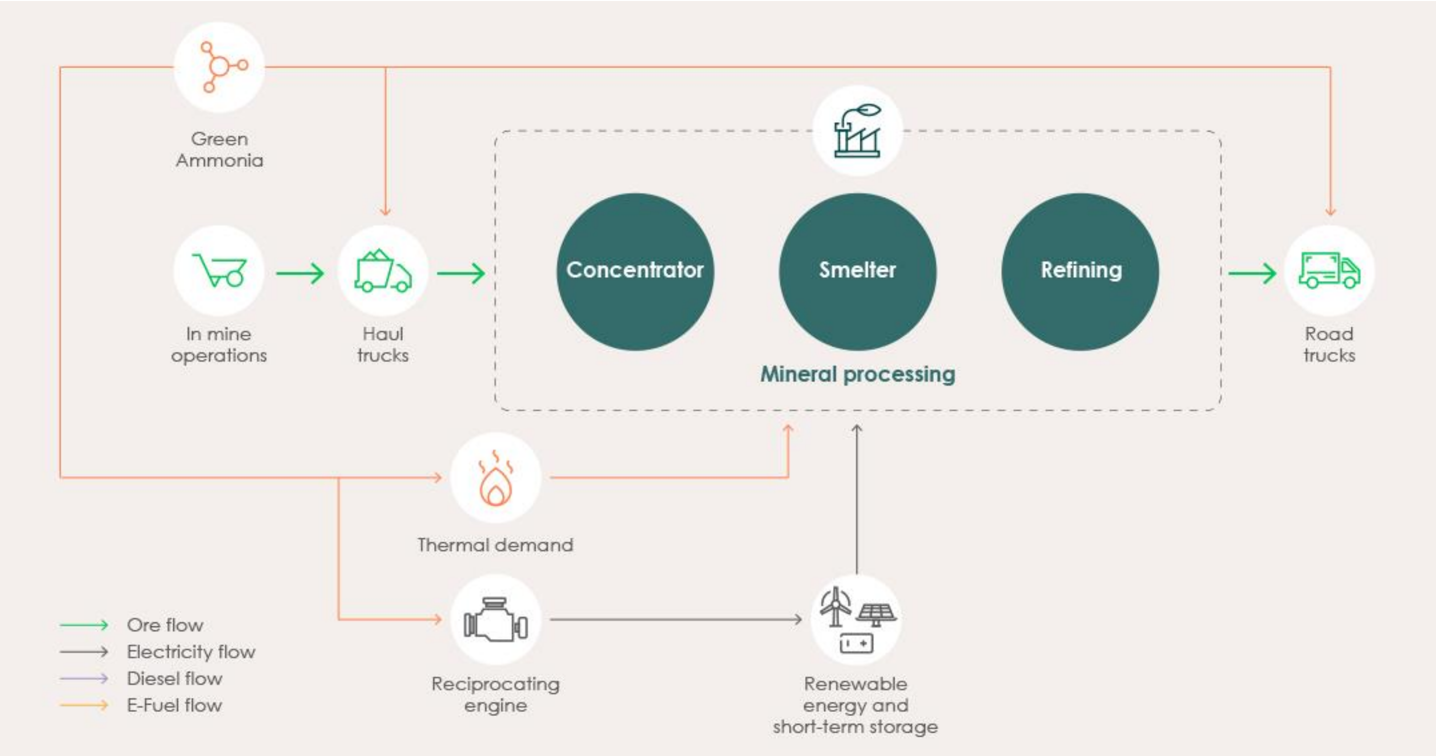

Figure 22: Energy value chain of the Hydrogen Importer pathway, Pathway 3, in 2040

In addition to the no-regrets capital investments in Phase 1 (common for all pathways and detailed in the Established Technology scenario), Phase 2 focuses on using imported e-fuels to displace natural gas used for thermal demand and diesel used by in-mine equipment. The intermediate phase also focuses on additional installations of on-site renewables and introducing battery systems.

Phase 3 achieves a zero-carbon energy system by displacing the remaining fossil fuels in the energy mix with e-fuels. This will require the adoption of e-fuel powered haulage and road trucks and utilising e-fuels to supplement on-site electricity generation. A detailed breakdown of the phases for Pathway 3 can be seen in Table 7. Implementation of all three phases of the pathway will see Mine Zero reach zero carbon emissions by 2035 (Figure 23).

Table 7: Pathway 3 phase breakdown

	Phase 1	Phase 2	Phase 3
Implementation date	Implementation year: 2024 In effect: 2025–2050	Implementation year: 2029 In effect: 2030–2050	Implementation year: 2034 In effect: 2035–2050
On-site renewables capacity	Installation of on-site renewables: – Solar PV capacity of 71 MW. – Wind energy capacity of 92 MW.	Increasing on-site renewables capacity: – Solar PV capacity of 78 MW. Total solar PV capacity = 149 MW. – Wind energy capacity of 34 MW. Total wind capacity = 126 MW.	Increased on-site renewables capacity: – Solar PV capacity of 11 MW. Total solar PV capacity = 160 MW.
Installation of short-term storage	No short-term storage	Li-ion battery of 149 MW/596 MWh	No additional investments in batteries
Fuel imports:	– Diesel for mobility and in-mine equipment. – Natural gas for on-site electricity generation and thermal demand.	– Diesel for haul trucks and road transport. – Green ammonia for process plant's thermal demand.	Green ammonia for mobility (haul trucks and road transport) and in-mine equipment
Summary:	No-regrets capital investments into on-site renewables to partially decarbonise electrical demand	– Invest in green ammonia imports. – Green ammonia powered in-mine equipment. – Process plant's thermal demand supplied through green ammonia imports. – Diesel for haul trucks and road transport.	Green ammonia powered haul trucks and road transport
Market-based solutions:	Offsets to meet short-term emissions reduction targets (if any)	Offsets to meet mid-term emissions reduction targets (if any)	Not required
CAPEX Requirement by phase	$317m	$377m	$15m
Internal Rate of Return vs BaU (over mine life)	26%	15% (Phase 1 and 2)	17% (Phase 1, 2, 3)

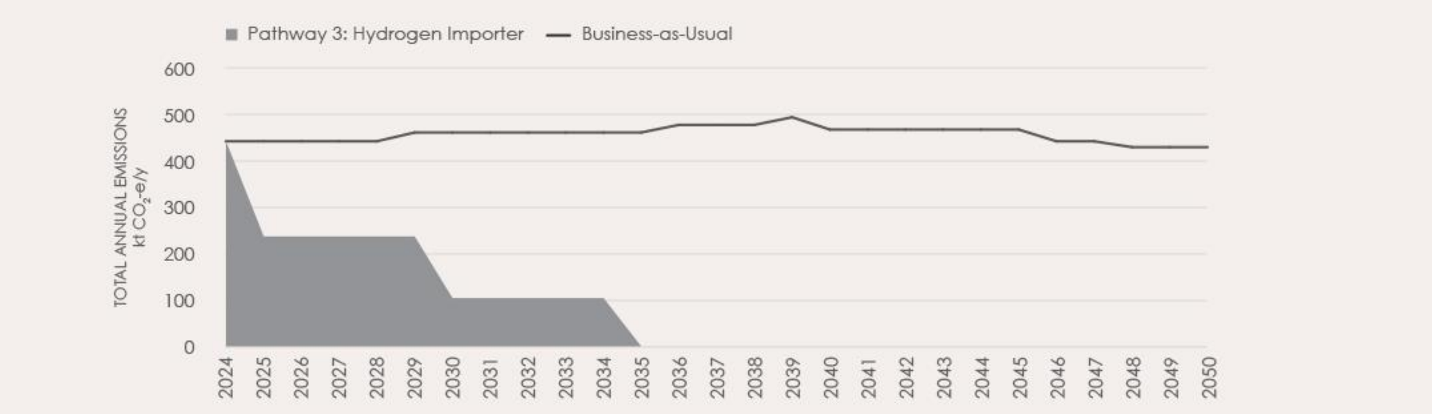

Figure 23: Emissions avoided compared to BaU for Pathway 3

The total CAPEX for this pathway is $709 million (Figure 24). These capital investments are primarily towards on-site renewables and battery systems. However, considerable operational expenditure ranging from $110 million to $140 million per year is incurred driven primarily by e-fuel imports, compared to an average of $50 million in the all-electric pathway.

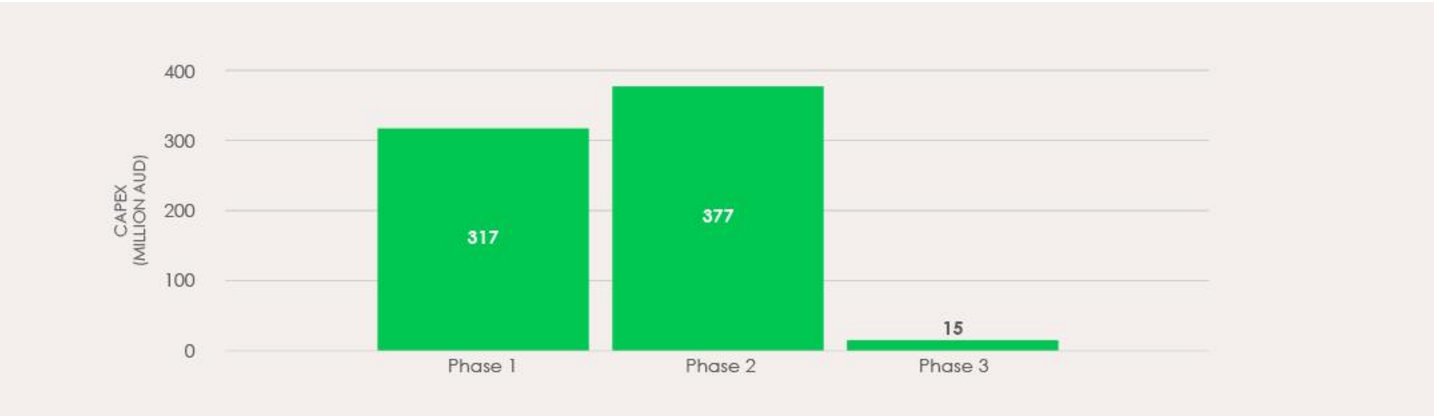

Figure 24: Phased CAPEX of Pathway 3

Further to the 205 ktCO_2-e emissions reductions achieved by the no-regrets capital investments in Phase 1, Phase 2 of the Hydrogen Importer pathway achieves an emissions reduction of 132 ktCO_2-e driven by decarbonisation of thermal and in-mine equipment. Shifting to e-fuel powered mobility and road trucks enable Mine Zero to reach zero carbon by reducing 104 ktCO_2-e of emissions in Phase 3 (Figure 25).

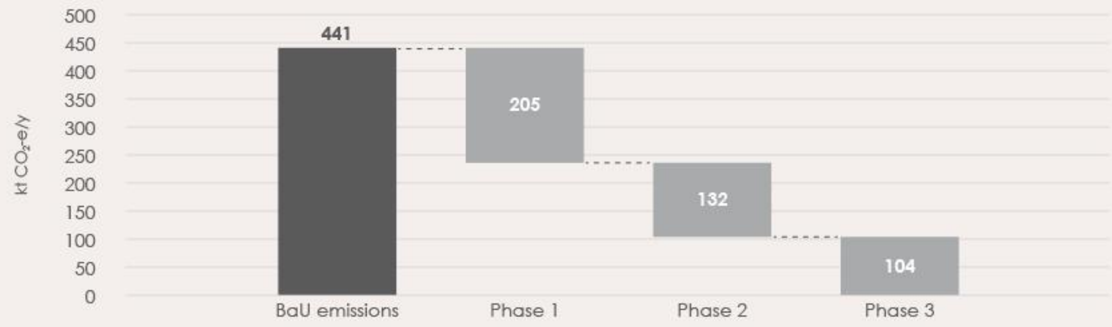

Figure 25: Annualised emissions reduction per phase in Pathway 3 ($ktCO_2$-e)

In addition to the emission savings, the pathway investments result in net cost savings compared to the BaU. These cost savings are predominantly from the avoided fuel expenditure for electricity generation but also due to the projected increase in fossil fuel expenditure beyond 2030 and decrease in e-fuel expenditure. The competing cost curves and avoided fuel expenditure establish a net saving from the BaU of $554 million, or a 20 per cent reduction (Figure 26).

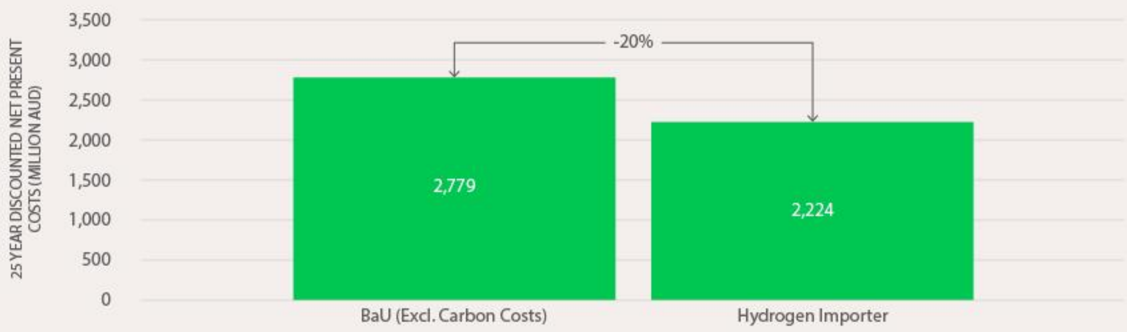

Figure 26: Savings from the Hydrogen Importer pathway

Other financial metrics – such as the payback period and the IRR – also emphasise the competitiveness of the Hydrogen Importer pathway:

– **Payback period:** This indicator represents the time elapsed, in years, for the pathway investments to reach cost parity with BaU energy costs. This is illustrated by the intersection of the net-present energy cost curves for the H2 pathway and BaU case (Figure 27). These cost curves include both the CAPEX and the OPEX. Cost savings from avoided fuel expenditure are realised beyond the point of cumulative net present costs crossover. The financial payback for the decarbonisation projects is achieved by 2036. Including a carbon price (averaging $50 per tCO_2-e) brings the payback period earlier to 2033.

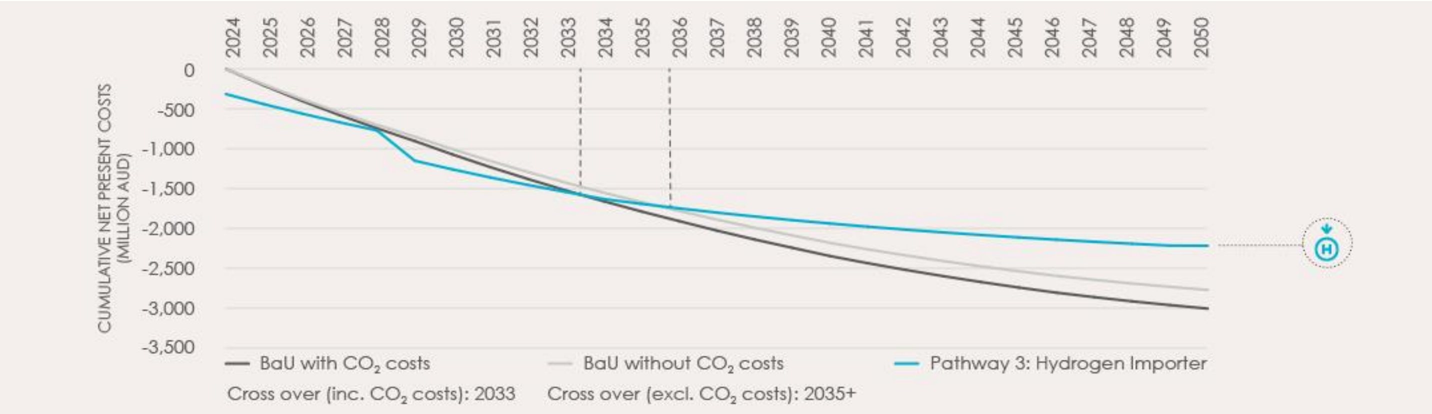

Figure 27: Pathway 3 net present cost comparison

- **IRR**: The investment in decarbonisation projects in this pathway will result in savings compared to BaU. The investments and savings over the 25-year horizon were considered to calculate the rate of return on investments. The pathway has an IRR of 17 per cent (21 per cent with carbon price), which is higher than the WACC of 7 per cent. This indicates a favourable business case for the Hydrogen Importer pathway compared to BaU.

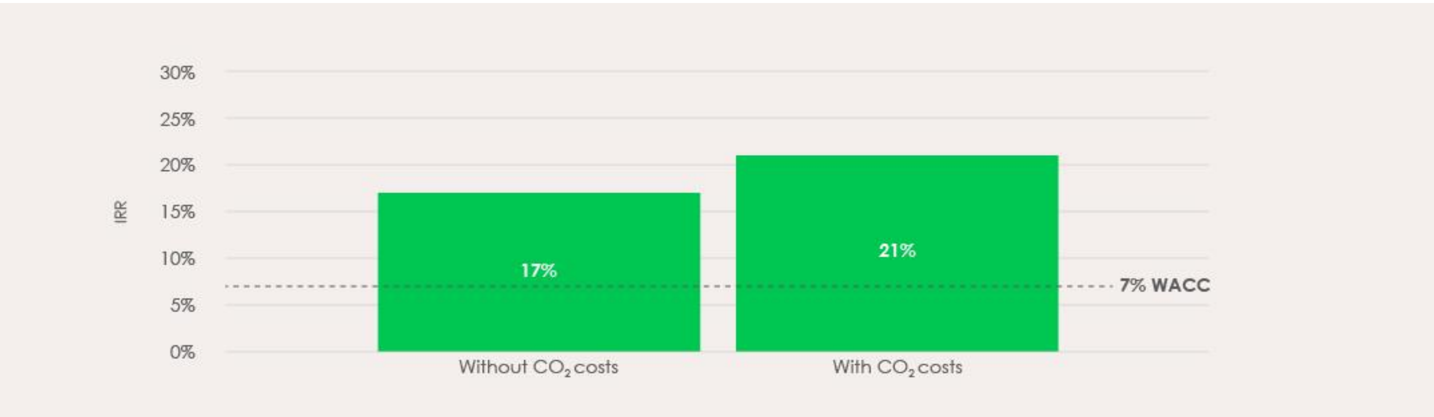

Figure 28: Pathway 3 internal rate of return

Key results from the Hydrogen Importer pathway are presented in Table 8 below:

Table 8: Outputs from the Hydrogen Importer pathway

Parameters	Business as usual	Pathway 3 Hydrogen Importer
Target year for zero carbon	NA	2040
Net present costs (Millions of AUD)	\$2,779 (no carbon costs) \$3,013 (with carbon costs)	\$2,224
Total annual system emissions (ktCO_2-e) in final state	~441 ktCO_2-e	0 ktCO_2-e
IRR	NA	17% (vs BaU without carbon costs) 21% (vs BaU including carbon costs)
Time to reach cost parity (years)	NA	12 years (vs BaU without carbon costs) ~10 years (BaU including carbon costs)

Pathway 4: Hydrogen Producer

A closed energy system pathway focused on energy resilience with all energy demand for Mine Zero being met by production on-site.

The Hydrogen Producer pathway focuses on maximising energy resilience at Mine Zero with a closed energy system. With no e-fuel imports, the Hydrogen Producer pathway seeks to increase on-site renewable capacity and storage (both short-term and seasonal). The priority is to directly electrify in-mine equipment and thermal demand while focusing on indirect electrification with on-site generated green hydrogen for haulage and road trucks. The final energy system of the Hydrogen Producer pathway in 2040 consists of significant on-site renewables and battery storage to power both Mine Zero's electricity demand and on-site green hydrogen production. The choices made in this pathway are one representation of an energy self-sufficient mine, however, these choices may not be optimal for different mining contexts. The energy value chain for the pathway is depicted in Figure 29.

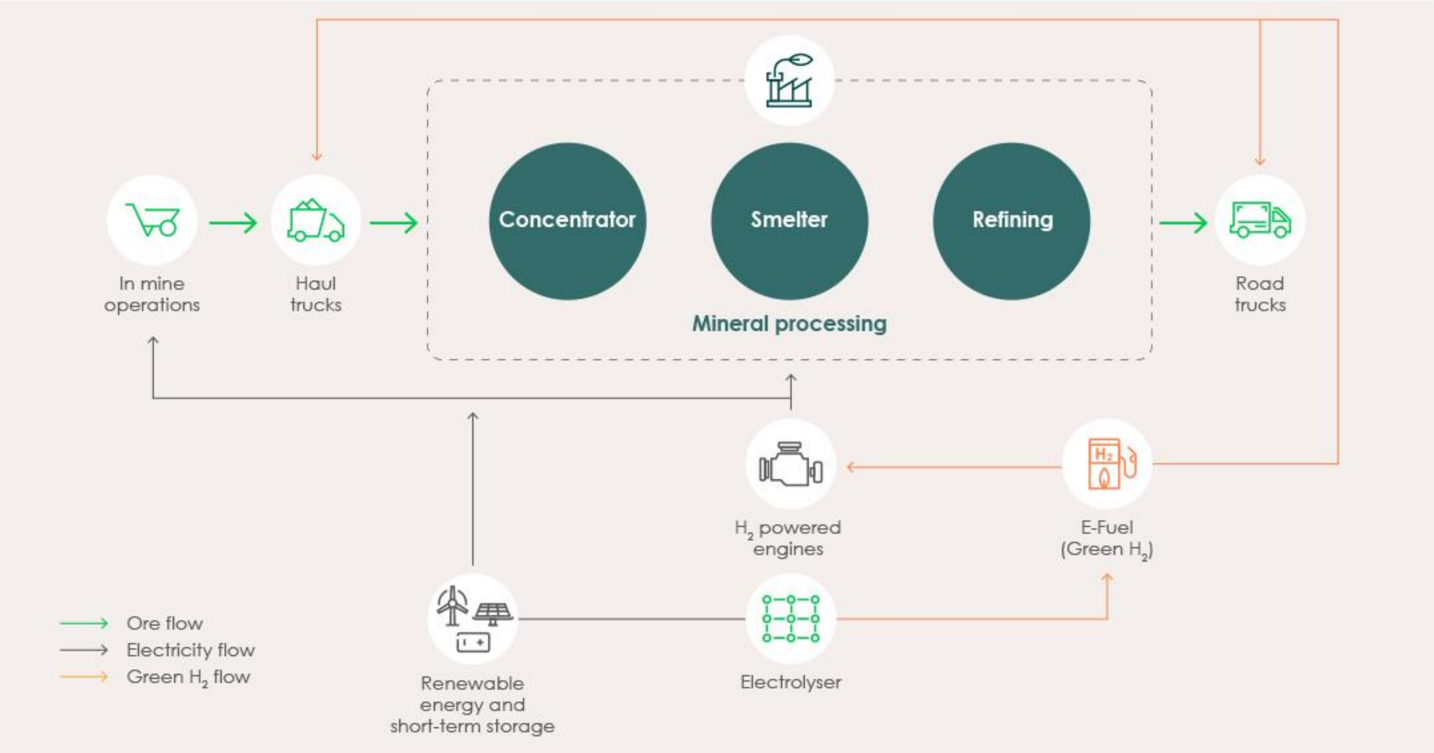

Figure 29: Energy value chain of the Hydrogen Producer pathway, Pathway 4, in 2040

In the intermediate phase, the Hydrogen Producer pathway prioritises the direct electrification of thermal demand from the processing plant and in-mine equipment. The resulting increase in electricity demand is supplied through additional on-site renewable installations, gas powered gensets, and battery systems. Phase 3 aims to achieve a 100 per cent closed energy system. This is achieved through increased on-site renewables and battery systems to produce and store green hydrogen onsite. This hydrogen caters to mobility and haulage demand to reach zero carbon by 2040. A detailed breakdown of the phases for the pathway is shown in Table 9. Implementation of all three phases of the pathway will see Mine Zero reach zero carbon emissions by 2035 (Figure 30).

Table 9: Pathway 4 phase breakdown

	Phase 1	Phase 2	Phase 3
Implementation date	Implementation year: 2024 In effect: 2025–2050	Implementation year: 2029 In effect: 2030–2050	Implementation year: 2034 In effect: 2035–2050
On-site renewables capacity:	Installation of on-site renewables: – Solar PV capacity of 71 MW. – Wind energy capacity of 92 MW.	Increasing on-site renewables capacity: – Solar PV capacity of 84 MW. Total solar PV capacity = 155 MW. – Wind energy capacity of 75 MW. Total wind capacity = 167 MW.	Increased on-site renewables capacity: – Solar PV capacity of 354 MW. Total solar PV capacity = 509 MW.
Installation of short-term storage:	No short-term storage	Li-ion battery of 109 MW/436 MWh	Additional Li-ion battery of 168 MW/674 MWh
Fuel imports:	– Diesel for mobility and in-mine equipment. – Natural gas for on-site electricity generation and thermal demand.	– Diesel for haulage and road trucks. – Natural gas for electricity generation.	No fuel imports.
Hydrogen production and storage:	No hydrogen production or storage	No hydrogen production or storage	– Electrolyser: 102 MW. – Compressed and liquid hydrogen storage.
Summary:	No-regrets capital investments into on-site renewables to partially decarbonise electrical demand	– Build on no-regrets investments to increase on-site renewables. – Electrified in-mine equipment. – Electrified thermal demand from process plant.	– Increased on-site renewables and seasonal storage. – Green hydrogen powered (produced on-site) for haul trucks and road transport.
Market-based solutions:	Offsets to meet short-term emissions reduction targets (if any)	Offsets to meet mid-term emissions reduction targets (if any)	Not required
CAPEX Requirement by phase	$317m	$410m	$2,284m
Internal Rate of Return vs BaU (over mine life)	26%	20% (Phase 1 and 2)	5% (Phase 1, 2 and 3)

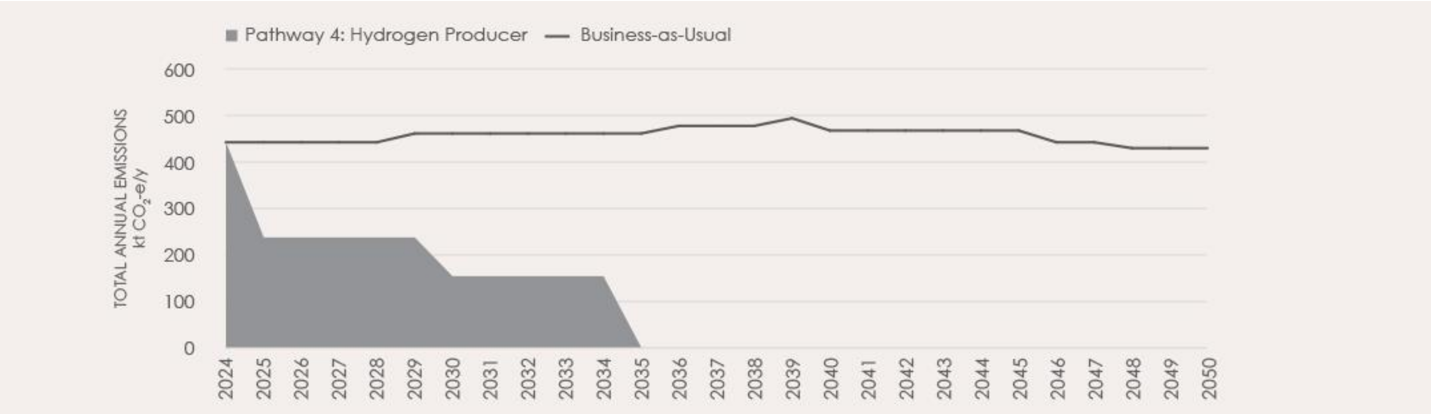

Figure 30: Emissions avoided compared to BaU for Hydrogen Producer Pathway 4

Hydrogen Producer is a capital-intensive pathway requiring $3,011 million of capital investment in decarbonisation technologies, based on current capital estimates. Beyond the no-regrets capital investment, the intermediate phase of Hydrogen Producer requires an investment of $410 million to decarbonise thermal demand and demand from in-mine equipment. Phase 3 will require a large capital investment of $2,284 million for hydrogen production and on-site storage to cater for mobility and haulage demand. The CAPEX split across the phase is depicted in Figure 31.

As indicated below, there is a relatively long payback period on this CAPEX in relation to the other pathways. The ongoing reliance on diesel fuel imports up to Phase 3 delays the start of energy self-sufficiency, leaving less of the mine life period to pay back the CAPEX. If green hydrogen production becomes commercially mature before 2035, the advancement of Phase 3 would provide a more favourable outlook for the Hydrogen Producer pathway.

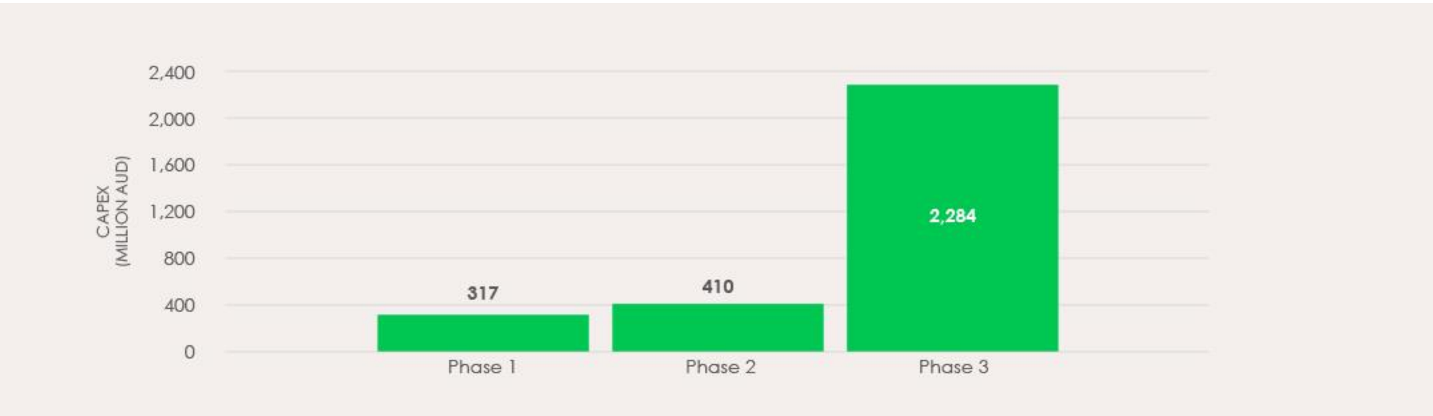

Figure 31: Phased CAPEX of Hydrogen Producer Pathway 4

Significant emissions reductions of 205 ktCO_2-e are achieved through the Phase 1 (Figure 32). Reductions in Phase 2 from the electrification of thermal demand and in-mine equipment, further reduce emissions by 83 ktCO_2-e (Figure 32). Phase 3 relies on renewable hydrogen powered mobility and haulage to reduce Mine Zero's emissions by a further 153 ktCO_2-e, hence reaching zero carbon production.

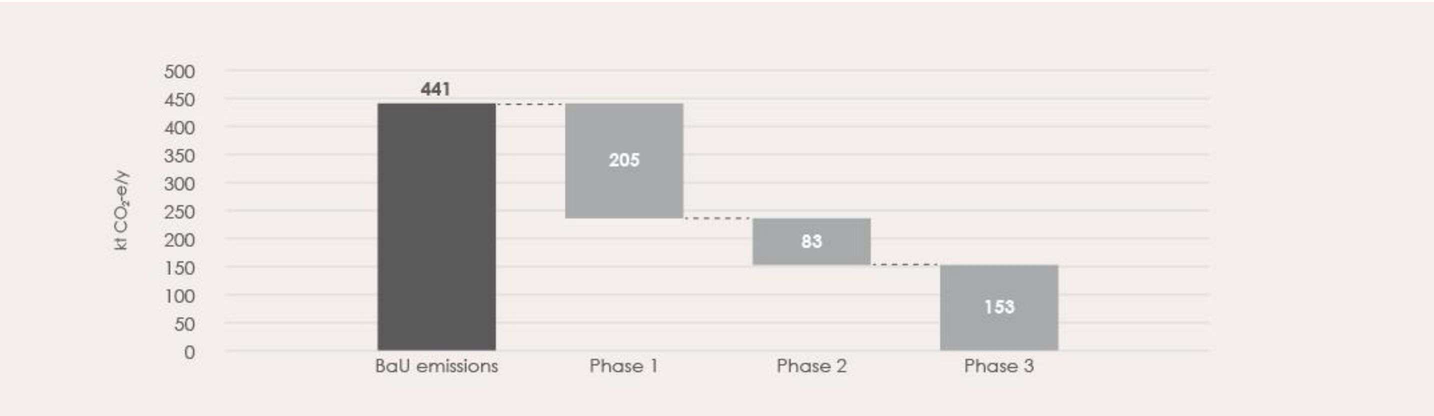

Figure 32: Annualised emissions reduction per phase in Hydrogen Producer Pathway 4 (ktCO_2-e)

The total net-present energy cost of the pathway exceeds the net-present energy cost of the BaU pathway by 5 per cent when carbon costs are excluded (Figure 33). This is driven by high capital investments into decarbonisation technologies, especially into on-site production and storage of hydrogen. This can be viewed as a premium to achieve a 100 per cent closed energy system and thereby negate any energy supply chain risks and commodity price fluctuations. Furthermore, Hydrogen Producer is the only pathway that explores and establishes the investments required for inter-seasonal storage on-site (in the form of hydrogen) – a critical aspect for achieving energy resilience in the long term.

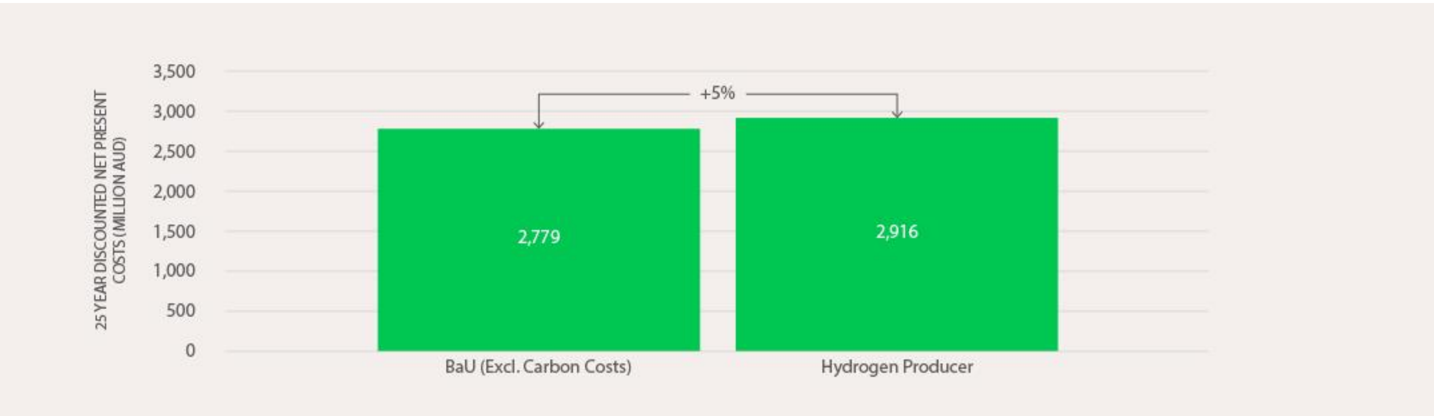

Figure 33: Cost difference from the Hydrogen Producer pathway

The total Hydrogen Producer pathway economics depict an unfavourable outcome for capital investment in decarbonisation projects compared to BaU, when carbon costs are excluded, although the intermediate stages (phases 1 and 2) appear to have reasonable returns. The payback period and IRR for the pathway are discussed below:

– **Payback period**: This indicator represents the time elapsed, in years, for the Hydrogen Producer pathway to reach cost parity with BaU energy costs. This is shown by the cost curves for the pathway and BaU (Figure 34). These cost curves include both the CAPEX required and the OPEX. Cost savings from avoided fuel expenditure are realised beyond the point of cumulative net present costs crossover. Unlike other pathways, Hydrogen Producer does not achieve cost parity without a carbon price. The inclusion of a carbon price (averaging $50 per tCO_2-e) does enable the pathway to achieve cost parity in 2047.

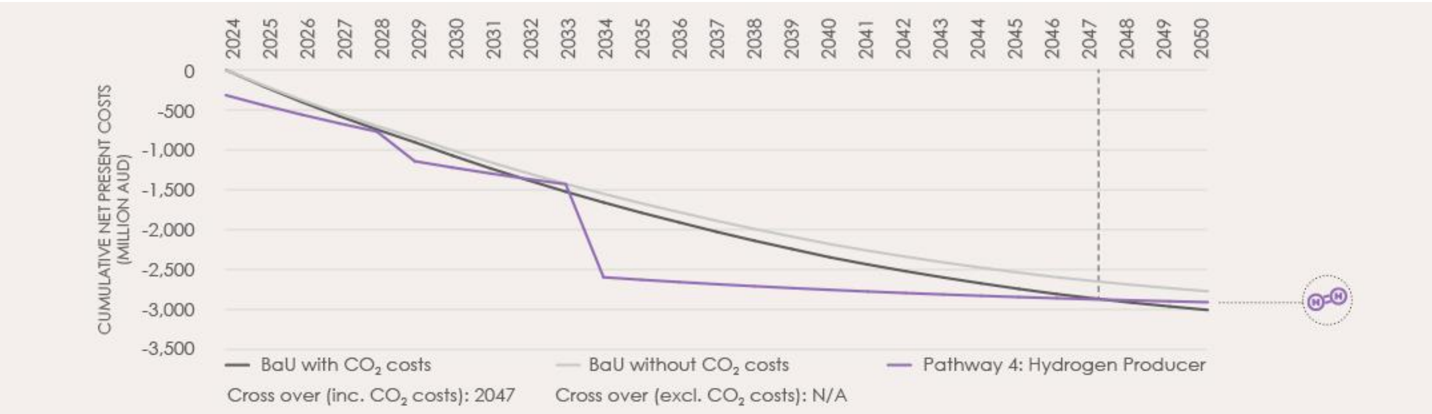

Figure 34: Pathway 4 net present cost comparison

– **IRR**: The pathway with an IRR of 5 per cent does not exceed the 7 per cent WACC without a carbon price, although as previously stated Phase 2 does show reasonable returns at ~20 per cent. With a carbon price, the IRR is 8 per cent, just above the 7 per cent WACC. This highlights a challenging business case for the Hydrogen Producer pathway.

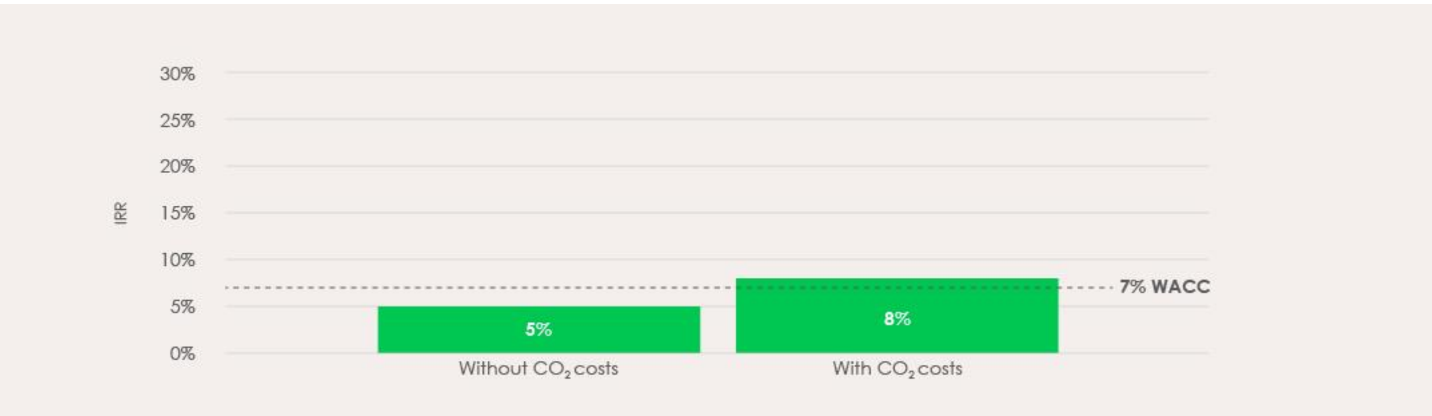

Figure 35: Pathway 4 Hydrogen Producer internal rate of return

Key results from the Hydrogen Producer pathway are presented in Table 10 below.

Table 10: Results for the Hydrogen Producer pathway

Parameters	Business as usual	Pathway 4 Hydrogen Producer
Target year for zero carbon	NA	2040
Net present costs (Millions of AUD)	$2,779 (no carbon costs) $3,013 (with carbon costs)	$2,916
Total annual system emissions (ktCO_2-e)	~44 ktCO_2-e	0 ktCO_2-e
IRR	NA	5% (vs BaU without carbon costs) 8% (vs BaU including carbon costs)
Time to reach cost parity (years)	NA	~23 years (BaU including carbon costs)

Finding the right pathway

Finding the right pathway for Mine Zero relies on an objective comparison of pathway economics as well as the risk profile aligning with the risk appetite of the business. There is also a range of external factors that may influence decisions, such as government funding, regulatory, capital market and customer perspectives and the wider geographic context.

The key to a robust decarbonisation roadmap is flexibility. The roadmap should outline what capital investment decisions should be made and when, taking into consideration decarbonisation targets. However, the roadmap should remain technology agnostic as far as practicable where technologies are currently at a nascent stage. It should also draw in to focus on the most promising emerging technologies and include a 'point of view' on which emerging technologies are most likely to form part of the zero carbon endgame.

Pathway comparisons

Key metrics for the comparison of pathways are shown in Table 11. Pathway comparisons are made exclusive of a carbon price to highlight the financial business case under conservative assumptions. The inclusion of a price on carbon improves the financial case compared to the BaU for all pathways.

Figure 36 depicts a timeline of net present costs for each pathway and the BaU including and excluding a price on carbon.

The Electrification pathway has the most favourable economics, reaching cost parity with the BaU case in 11 years, the lowest net present costs of $1.8 billion (a 34 per cent saving of $940 million) and an IRR of 20 per cent. Established Technology and Hydrogen Importer have similar economics and achieve the outcome of net-zero or zero-carbon mining with favourable economics compared to the BaU case. However, net present costs are higher and the internal rate of return lower for both pathways compared to Electrification. Established Technology will avoid the least overall on-site emissions of the four pathways. This is attributed to the pathway's reliance on carbon offsets at an average annualised cost of $166 million. Hydrogen Producer is the only pathway that will result in unfavourable economics compared to the BaU case. It has the highest net present costs of $2.9 billion and does not reach cost parity with the BaU over the life of the mine.

The replacement CAPEX of the gensets in the BaU pathway was not included in the analysis. But, where applicable, replacement CAPEX for on-site renewables and batteries has been considered. Even with these considerations, **the analysis indicates a favourable case for decarbonisation for at least 3 out of the 4 pathways considered**.

Based on the financial business case pathways were prioritised as follows:

1. Electrification.
2. Established Technology.
3. Hydrogen Importer.
4. Hydrogen Producer.

Note that the pathway 4 analysis is not a generalised judgement on the application of hydrogen technology in the mining environment, but rather the outcome of a specific set of assumptions to a specific hypothetical scenario.

Table 11: Comparison of key metrics for decarbonisation pathways (excluding carbon cost)

Parameters	Pathway 1 Established Technology	Pathway 2 Electrification	Pathway 3 Hydrogen Importer	Pathway 4 Hydrogen Producer
Target year for zero carbon	2040	2040	2040	2040
Net present costs (Millions of AUD)	$2,190	$1,838	$2,223	$2,916
Time to reach cost-parity vs BaU (years)	10	11	12	Does not reach cost parity with BaU
IRR (%) vs BaU	18%	20%	17%	NA
Annual pathway emissions ($ktCO_2$-e)	4,719	1,952	1,706	1,952
Annual emissions avoided vs BaU ($ktCO_2$-e)	7,620	10,388	10,633	10,388

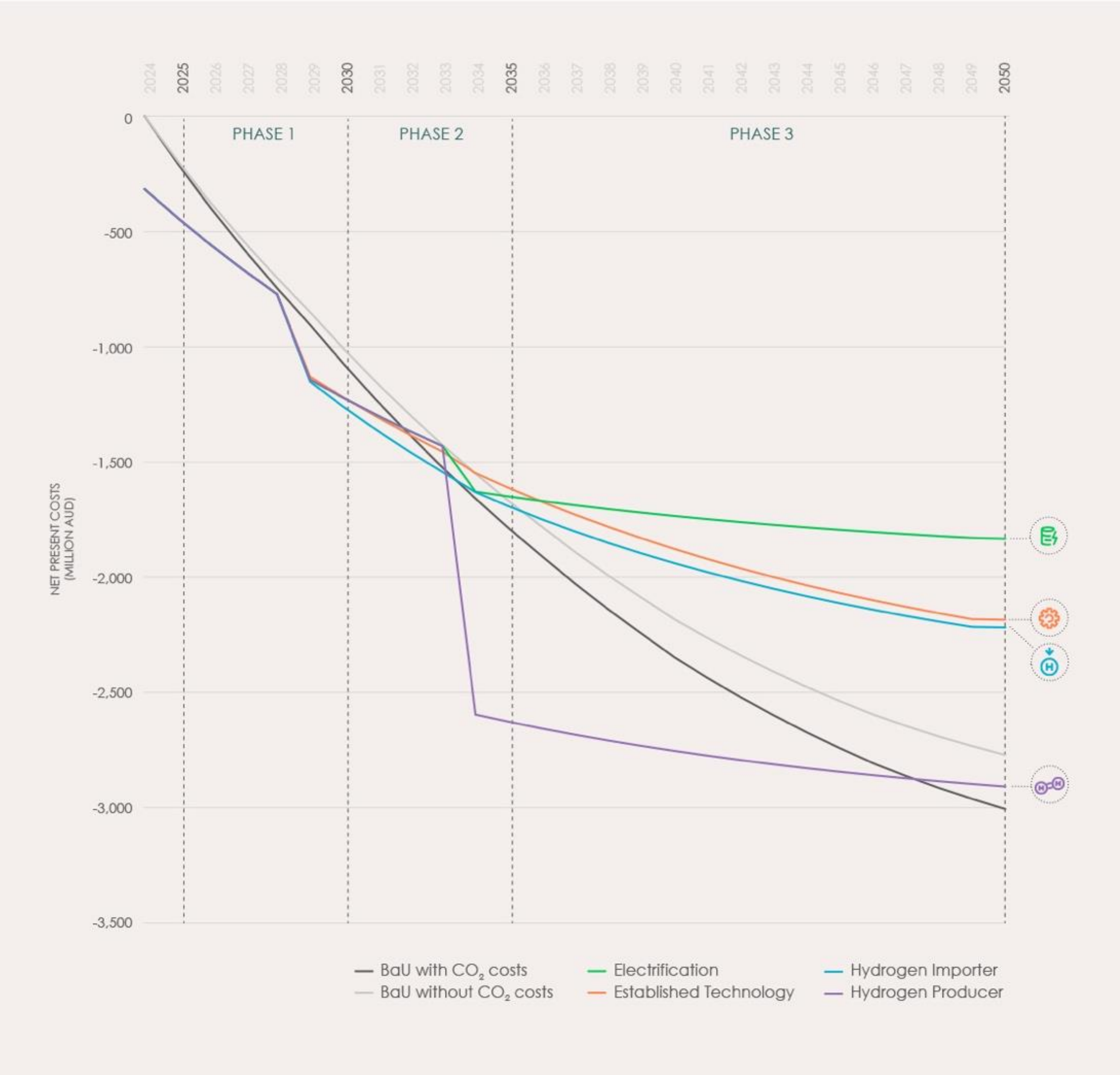

Figure 36: Timeline comparing the four pathways analysed

Each pathway faces a range of enablers and barriers that need to be carefully considered as they impact the risk profile of the pathway. Table 12 outlines the key enablers and barriers for each pathway. The list is not exhaustive and is intended to be illustrative.

Next steps

If the owner of Mine Zero chose to proceed with the Electrification pathway, practical next steps would include:

- Securing funding to invest in Phase 1 to increase renewable share at Mine Zero's location and significantly reduce the carbon footprint.
- Making a public commitment to Electrification noting the uncertainties with the pathway and desire to monitor progress with e-fuels.
- Monitoring the commercial maturity for electric haul trucks and in-mine equipment.
- Establishing a plan to pilot electrified solutions at Mine Zero and to capture lessons learned.
- Monitoring advancements in e-fuel technology and applications.
- Weighing up the business' appetite to participate in the carbon offset market in the short term to address hard-to-abate emissions that will be mitigated in Phase 3 implementation.
- Reassessing Mine Zero's decarbonisation roadmap prior to Phase 2 implementation.

Table 12: Key enablers and barriers for each pathway

Pathway	Key enablers	Key barriers	Considerations
Established Technology	– Solutions are low risk with a high degree of technological and commercial maturity. – Carbon neutrality can be achieved quickly, and products marketed with environmental credentials. – Carbon offsets provide opportunity to have positive environmental and social impact through co-benefits.	– Carbon offsets widely viewed as a mechanism to manage residual emissions for hard-to-abate emissions. – The future price of carbon offsets is uncertain with expectations of substantial increases beyond current prices.	– It is relevant to consider whether there is appetite to adopt a Science-based Target (SBT). The SBT initiative requires that companies set targets based on emissions reductions through direct action within their own boundaries or their value chains.
Electrification	– Long-term, low-cost green electricity infrastructure and supply contracts are readily accessible and provide price security. – Aggregation of energy demand across all mine activities into electrical energy simplifies infrastructure and reduces duplication costs. – Significant research and development being channelled into electrification by OEMs and mining consortia.	– Electrification of haulage and mobility equipment has low maturity and current battery technology has practical limitations in mining. – Some processes, including high heat processes, are difficult to fully electrify.	– Mining consortia are actively working with OEMs on overcoming practical limitations of electric vehicles. – Mine Zero is in a remote part of WA with refined product needing to be transported long distances.
Hydrogen Importer	– There is strong support from government and industry for hydrogen which has resulted in funding to advance the development of regional infrastructure. – E-fuels provide greater flexibility and are more suited to existing operating practices. – Emerging derivatives of green hydrogen, such as green ammonia, overcome practical limitations of hydrogen storage and transport.	– Green hydrogen is at a nascent stage and while the technology is promising, its practicality and commercial viability in mining are unproven. – The emerging e-fuels market may create price volatility.	– State and Federal governments have recently announced funding for the development of hydrogen hubs. – Local green ammonia production plans have been announced. – OEMs have announced their intention to convert diesel haulage trucks to ammonia and develop new ammonia fuelled haulage trucks.
Hydrogen Producer	– A closed energy system establishes self-sufficiency and eliminates market risks with imported fuels.	– Hydrogen production will require secure, long-term access to water. – The on-site energy infrastructure will require specialist on-site workforce capabilities to operate and maintain equipment.	– The remote location of Mine Zero may have limited access to water and experience regular periods of drought.

Appendix A: Modelling assumptions

This appendix contains the key assumptions used to model the four decarbonisation pathways. These factors are based on the specific mine context, including location and access to infrastructure. Within the modelling workbook, data is structured as required for the Prosumer modelling. Major assumptions used are summarised below.

Values are reported at 10-year intervals and it should be noted that a range of unit-conversion, modifying, and average practices were used to shape the data for Prosumer.

Table 13: Summary of key assumptions used as inputs within the Prosumer model. The 'Ref.' columns refer to where the information came from, with multiple references implying that data has been aggregated in various ways.

Power generation

Solar PV

References

Source	Link	Ref. ID
GenCost 2020-21	https://publications.csiro.au/publications/publication/PIcsiro:EP2021-0160	A
NREL 2021 Annual Technology Baseline	https://atb.nrel.gov/electricity/2021/data	B
ENGIE Internal estimates	Data obtained from Engie global sources. Conservative estimates preferred.	C
Renewable ninja	Data from: renewables.ninja	D

Technical parameters

Parameters	Unit	Ref.	Value
Equipment life	years	A	25.00
Capacity loss	per year	C	0.01
Footprint	m^2/kWp	C	12.75

Economic parameters

Item	Units	Ref.	2020	2030	2040	2050
Solar PV: CAPEX Min	(AUD/kWp)	A+B	1,730.75	903.90	676.20	631.35
Solar PV: CAPEX Nominal	(AUD/kWp)	A+B	2,177.22	1,557.66	1,270.44	1,085.77
Solar PV: CAPEX Max	(AUD/kWp)	A+B	2,674.62	2,335.08	1,981.45	1,626.06
Solar PV: OPEX	(AUD/kWp per year)	A+B	24.18	22.08	19.84	17.99

Wind

References

Source	Link	Ref. ID
GenCost 2020–21	https://publications.csiro.au/publications/publication/PIcsiro:EP2021-0160	A
NREL 2021 Annual Technology Baseline	https://atb.nrel.gov/electricity/2021/data	B
ENGIE Internal estimates	Data obtained from Engie global sources. Conservative estimates preferred.	C
Renewable ninja	Data from: renewables.ninja	D

Technical parameters

Parameters	Unit	Ref.	Value
Equipment life	years	C	25.00
Capacity loss	per year	C	–

Economic parameters

Item	Units	Ref.	2020	2030	2040	2050
Wind: CAPEX Min	(AUD/kWp)	A+B+C	2,109.77	1,181.81	970.83	849.48
Wind: CAPEX Nominal	(AUD/kWp)	A+B+C	2,460.63	1,910.78	1,766.18	1,675.49
Wind: CAPEX Max	(AUD/kWp)	A+B+C	2,828.95	2,772.40	2,715.85	2,666.55
Wind: OPEX	(AUD/kWp per year)	A+B+C	41.31	41.31	40.79	40.20

Electrolysers: Pressurised alkaline cost (10 MW)

References

Source	Link	Ref. ID
GenCost 2020-21	https://publications.csiro.au/publications/publication/PIcsiro:EP2021-0160	A
ENGIE Internal estimates	Data from Engie global sources. Conservative estimates preferred.	B

Technical parameters

Parameters	Unit	Ref.	Value
Main efficiency pressurised alkaline	kWh_el/kg H_2	C	57.48
Technical life	years	C	20.00

Economic parameters: power component

Item	Units	Ref.	2020	2030	2040	2050
Pressurised alkaline: CAPEX Min	(AUD/kW)	A	2,797.95	1,174.15	492.20	406.76
Pressurised alkaline: CAPEX Nominal	(AUD/kW)	A	3,162.90	1,475.50	695.05	589.68
Pressurised alkaline: CAPEX Max	(AUD/kW)	A	3,527.85	1,811.05	929.89	802.58
Pressurised alkaline: OPEX	(AUD/kW per year)	A	17.76	8.29	3.90	3.31

Reciprocating engines

References

Source	Link	Ref. ID
GenCost 2020–21	https://publications.csiro.au/publications/publication/PIcsiro:EP2021-0160	A
ENGIE Internal estimates	Data from Engie global sources. Conservative estimates preferred.	B
US DoE	https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf	C

Technical parameters

Parameters	Unit	Ref.	Value
Efficiency	[–]	C	0.42
Technical life	years	C	20.00

Economic parameters: power component

Item	Units		2020	2030	2040	2050
Engines: CAPEX Min	(AUD/kW)	A	1,657.15	1,657.15	1,657.15	1,657.15
Engines: CAPEX Nominal	(AUD/kW)	A	2,457.65	2,457.65	2,457.65	2,457.65
Engines: CAPEX Max	(AUD/kW)	A	3,393.00	3,393.00	3,393.00	3,393.00
Engines: OPEX	(AUD/kW per year)	A	28.36	28.36	28.36	28.36

Compressed hydrogen

Source	Link	Ref. ID
ENGIE Internal estimates	Data from Engie global sources. Conservative estimates preferred.	A

Technical parameters

Parameters	Unit	Ref.	Value	
Low pressure: Conversion efficiency	kWh_el/kg H_2	A	1.56	Note: ENGIE Impact added a 30% premium to costs to account for the isolated installation costs for hydrogen.
Medium pressure: Conversion efficiency	kWh_el/kg H_2	A	1.27	
High pressure: Conversion efficiency	kWh_el/kg H_2	A	0.52	
Technical life	years	A	20.00	

Economic parameters: low pressure

Item	Units	Ref.	2020	2030	2040	2050
Compressed hydrogen: CAPEX	(AUD per kg H_2/h)	A	4,033.90	4,033.90	4,033.90	4,033.90
Compressed hydrogen: OPEX	(AUD/kW)	A	104.88	104.88	104.88	104.88

Economic parameters: medium pressure

Item	Units	Ref.	2020	2030	2040	2050
Compressed hydrogen: CAPEX	(AUD per kg H_2/h)	A	4,733.30	4,733.30	4,733.30	4,733.30
Compressed hydrogen: OPEX	(AUD/kW)	A	123.07	123.07	123.07	123.07

Economic parameters: high pressure

Item	Units	Ref.	2020	2030	2040	2050
Compressed hydrogen: CAPEX	(AUD per kg H_2/h)	A	3,398.80	3,398.80	3,398.80	3,398.80
Compressed hydrogen: OPEX	(AUD/kW)	A	88.37	88.37	88.37	88.37

Energy storage

Battery systems: Li-Ion

References

Source	Link	Ref. ID
GenCost 2020-21	https://publications.csiro.au/publications/publication/PIcsiro:EP2021-0160	A
Rocky Mountain Institute	https://rmi.org/insight/breakthrough-batteries/	B
Bloomberg	https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf	C
US DoE	Data from previous client work. Conservative estimates preferred.	D
ENGIE Internal estimates	Data from previous client work. Conservative estimates preferred.	E

Notes: In the absence of credible sources stating CAPEX (and associated Fixed O&M) for a 1-hour battery system, we estimated these values using costs of a 4h and 8h battery. These estimates for a 1-hour battery system costs were used in our modelling. Our models consider the power and energy components of the short-term storage options separately. However, we did impose an E/P (energy to power ratio) constraint of 4 on the battery sizing. We have assumed a 10-year cycle time in our modelling. This equates to ~3500 cycles for the lifetime of the battery.

Technical parameters

Parameters	Unit	Ref.	Value
Technical life	*years*	E	10.00
Round-trip efficiency	[–]	E	0.85

Economic parameters: power component

Item	Units	Ref.	2020	2030	2040	2050
Li-ion: CAPEX Min	(AUD/kW)	A+B+C+D+E	460.00	349.60	248.40	138.00
Li-ion: CAPEX Nominal	(AUD/kW)	A+B+C+D+E	520.00	416.00	322.40	223.60
Li-ion: CAPEX Max	(AUD/kW)	A+B+C+D+E	580.00	487.20	406.00	324.80
Li-ion OPEX	(AUD/kW per year)	A+B+C+D+E	4.00	3.20	2.48	1.72

Economic parameters: energy component

Item	Units	Ref.	2020	2030	2040	2050
Li-ion: CAPEX Min	(AUD/kWh)	A+B+C+D+E	369.15	136.85	108.10	101.20
Li-ion: CAPEX Nominal	(AUD/kWh)	A+B+C+D+E	417.30	239.20	178.10	162.50
Li-ion: CAPEX Max	(AUD/kWh)	A+B+C+D+E	465.45	361.05	261.00	234.90
Li-ion OPEX	(AUD/kWh per year)	A+B+C+D+E	6.42	3.68	2.74	2.50

Hydrogen short-term storage: Compressed H_2

Economic parameters: low pressure

Item	Units	Ref.	2020	2030	2040	2050
Short-term storage hydrogen: CAPEX	(AUD per kg H_2)	A+B+C+D+E	2,353.00	2,105.32	2,105.32	2,105.32
Short-term storage hydrogen: OPEX	(AUD per kg H_2)	A+B+C+D+E	40.00	35.79	35.79	35.79

Economic parameters: medium pressure

Item	Units	Ref.	2020	2030	2040	2050
Short-term storage hydrogen: CAPEX	(AUD per kg H_2/h)	A+B+C+D+E	3,065.40	2,742.73	2,742.73	2,742.73
Short-term storage hydrogen: OPEX	(AUD/kW)	A+B+C+D+E	52.11	46.63	46.63	46.63

Economic parameters: high pressure

Item	Units	Ref.	2020	2030	2040	2050
Short-term storage hydrogen: CAPEX	(AUD per kg H_2/h)	A+B+C+D+E	4,338.10	3,881.46	3,881.46	3,881.46
Short-term storage hydrogen: OPEX	(AUD/kW)	A+B+C+D+E	73.75	65.98	65.98	65.98

Hydrogen seasonal storage: liquid hydrogen

References

Source	Link	Ref. ID
Bloomberg	https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf	A
Kawasaki	https://global.kawasaki.com/en/corp/newsroom/news/detail/?f=20201224_8018	B
ENGIE Internal estimates	Data from Engie global sources. Conservative estimates preferred.	C

Technical parameters

Parameters	Unit	Ref.	Value
Liquid H_2: Liquefaction efficiency	kWh_el/kg H_2	A+B+C	12.00
Liquid H_2: Liquefaction technical life	years	A+B+C	20.00
Liquid H_2: Storage boil off rates	% per day	A+B+C	0.20
Liquid H_2: Storage efficiency	[–]	A+B+C	1.00
Liquid H_2: Regasification efficiency	kWh_el/kg H_2	A+B+C	0.95

Economic parameters: liquefaction component

Item	Units	Ref.	2020	2030	2040	2050
Liquification: CAPEX Min	(AUD per kg H_2/h)	A+B+C	#N/A	18,795.78	18,795.78	18,795.78
Liquification: CAPEX Nominal	(AUD per kg H_2/h)	A+B+C	#N/A	23,747.02	23,747.02	23,747.02
Liquification: CAPEX Max	(AUD per kg H_2/h)	A+B+C	#N/A	29,275.10	29,275.10	29,275.10
Liquification: OPEX	(AUD per kg H_2/h per Item)	A+B+C	#N/A	548.01	548.01	548.01

Economic parameters: energy storage component

Item	Units	Ref.	2020	2030	2040	2050
Liquification: CAPEX Min	(AUD per kg H_2/h)	A+B+C	#N/A	191.05	191.05	191.05
Liquification: CAPEX Nominal	(AUD per kg H_2/h)	A+B+C	#N/A	409.30	409.30	409.30
Liquification: CAPEX Max	(AUD per kg H_2/h)	A+B+C	#N/A	672.17	672.17	672.17
Liquification: OPEX	(AUD per kg H_2/h per Item)	A+B+C	#N/A	3.15	3.15	3.15

Economic parameters: regasification component

Item	Units	Ref.	2020	2030	2040	2050
Liquification: CAPEX Min	(AUD per kg H_2/h)	A+B+C	#N/A	10,880.42	10,880.42	10,880.42
Liquification: CAPEX Nominal	(AUD per kg H_2/h)	A+B+C	#N/A	13,745.76	13,745.76	13,745.76
Liquification: CAPEX Max	(AUD per kg H_2/h)	A+B+C	#N/A	16,944.82	16,944.82	16,944.82
Liquification: OPEX	(AUD per kg H_2/h per Item)	A+B+C	#N/A	380.65	380.65	380.65

Prices

Carbon price

References

Source	Link	Ref. ID
ENGIE Internal estimates	Data from Engie global sources. Conservative estimates preferred.	A

Prices

Item	Units	Ref.	2020	2030	2040	2050
Low	(AUD per tCO_2-e)	A	14.00	20.63	22.76	26.54
Medium	(AUD per tCO_2-e)	A	17.00	35.81	54.77	73.44
High	(AUD per tCO_2-e)	A	19.00	52.78	88.87	124.89

Fuel prices

References

Source	Link	Ref. ID
CSIRO Possible Futures: Scenario Modelling of Australian Alternative Transport Fuels to 2050	https://publications.csiro.au/rpr/download?pid=csiro:EP116462&dsid=DS4	A
AEMO Wholesale, Delivered Gas Price Scenarios | 2018 – 2040	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/CORE-Eastern-Australia-Gas-Price-Projections-Databook_16-January-2019.xlsx	B
Cesaro et.al, Applied Energy, Volume 282, Part A, 15 January 2021	https://www.researchgate.net/publication/347909874_Ammonia_to_power_Forecasting_the_levelized_cost_of_electricity_from_green_ammonia_in_large-scale_power_plants	C

Diesel

Item	Units	Ref.	2020	2030	2040	2050
Min	(AUD per litre)	A+B+C	1.38	1.52	1.60	1.55
Nominal	(AUD per litre)	A+B+C	1.52	2.01	2.08	2.04
Max	(AUD per litre)	A+B+C	1.65	2.50	2.55	2.53

NG

Item	Units	Ref.	2020	2030	2040	2050
Min	(AUD per MWh)	A+B+C	68.00	70.79	74.52	74.52
Nominal	(AUD per MWh)	A+B+C	68.00	75.92	82.75	82.75
Max	(AUD per MWh)	A+B+C	68.00	81.04	90.99	90.99

Green Ammonia

Item	Units	Ref.	2020	2030	2040	2050
Min	(AUD per MWh)	A+B+C	149.73	106.95	83.85	83.85
Nominal	(AUD per MWh)	A+B+C	203.61	175.10	131.85	131.85
Max	(AUD per MWh)	A+B+C	270.08	239.88	161.41	161.41

Financial

Item	Units	Ref.	Value
USD to AUD	AUD/USD	–	1.34
Weighted average cost of capital	[–]	–	0.07

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