Technology solutions for decarbonisation

Mining in a low-emissions economy

cefc

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Minerals Research Institute of Western Australia

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.

Table of Contents

Case studies

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 the 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, available 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-Emission Economy: Technology Solutions for Decarbonisation*** is on the use of technology to **decarbonise mining operations**. It provides **insights into available and emerging technologies** and **showcases examples** of how mining companies are leveraging technology in the pursuit of zero carbon mining.

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
EDR	Economically Demonstrated Resources
EF	Emission Factor
EMC	Electric Mine Consortium

Term	Description
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	ICMMs 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
MJ	Megajoule
MoU	Memorandum of Understanding
MVR	Mechanical Vapour Recompression

Term	Description
MW	Megawatt
MWh	Megawatt-hour
N_2O	Nitrous Oxide
NGERS	National Greenhouse and Energy Reporting Scheme
NPC	Net present cost
NPV	Net present value
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	Stand-alone 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
TRL	Technology Readiness Level

Term	Description
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 CO2-e emissions and no reliance on carbon offsets

Key Concepts

Zero carbon vs zero emission vs net zero: Throughout Mining in a Low-emissions economy, 'zero carbon' is used as shorthand to describe the abatement of all greenhouse gas (GHG) intensive activity. Most greenhouse gas emissions occur as carbon dioxide (CO_2) or methane (CH_4) emissions. Other non-carbon forms of GHGs, such as nitrous oxide (N_2O), sulphur hexafluoride (SF_6), and hydrofluorocarbons (HFCs), are implied in these reports to be covered by the use of 'zero carbon'.

Zero carbon is referred to rather than 'net zero' to reinforce the need to reduce emissions at the mine site. Net zero includes the use of carbon removal or offsets to neutralise any remaining emissions. Instruments such as high-integrity carbon offsets can be used to manage residual emissions from hard-to-abate activities where low-emissions technologies have not reached commercial readiness, or where a company has been unable to put in place other measures to reduce effective emissions in line with a zero-emissions goal. Best practice offset usage is not mutually exclusive with abatement on the mine site. A successful decarbonisation strategy will usually factor in the commodity pricing of carbon and will ideally use carbon instruments solely to manage residual risk.

Deep decarbonisation: Is also used to refer to the desired end state of zero-carbon mining, and is often used to describe the hard-to-abate or 'last 20 per cent' of the decarbonisation journey.

Technology solutions for decarbonisation

Introduction

Technology plays a significant role in the decarbonisation of mining – whether in terms of energy source and demand, or emissions impact. Understanding current and emerging technologies and their application presents a challenge for the mining sector, given the pace of change and the individual circumstances of each mining operation.

This report is designed to be a starting point for mining companies in their decarbonisation journey. It covers the major emissions-intensive activities within a mining operation – stationary energy, material movement, in-mine operations, and mineral processing. As fuels are universally required across these activities, fuel choice is considered first. The report concludes by considering general trends in financial and strategic instruments, including carbon offsets and green finance, that are enablers of a zero-carbon mine.

Analysis of each activity is comprised of several elements:

- A **summary** highlights the key messages within each section.
- An **'in brief'** section profiles the options to decarbonise these activities for each mine, with **case studies** provided to demonstrate who has acted or is investing in trials of these low or zero carbon technologies.
- Technology **heatmaps** then provide further details on the attributes of each option, to provide a comparative assessment of a range of technical, environmental, and commercial factors relevant to strategy and implementation. Common heatmap categories are described in Table 1.
- **Decarbonisation scores** are assigned as a comparative analysis of stationary energy and material movement technologies, scoring each based on a range of social, technical, market, regulatory and economic factors. These scores provide a reference point for decision makers, in advance of site-specific planning and assessment. The methodology is set out in Appendix B.

Table 1: Description of common heatmap categories used in this guide. Additional categories used in specific heatmaps are introduced in the relevant section.

Factor	Description
Emission benefit	The emissions avoided per unit of base-case fuel. The avoided emissions are calculated using the emissions that would be produced in the base case, compared to the low-emission alternative. This calculation is explained in Appendix A.
Technology readiness	The Technology Readiness Level (TRL) is an indication of how technically mature the technology is. This is a commonly used metric, for example in use by NASA and ARENA [1]. It is a representation of functional maturity and represents if the technology has been proven to work in relevant contexts.
Commercial readiness	The Commercial Readiness Index (CRI) is analogous to the TRL but represents commercial maturity. Again, it is a widely used metric, see ARENA [1]. After technologies are proven there are still a range of commercial development steps to pass through before the technology matures to the most efficient, low-risk, commercial scale.
REC Market	The Renewable Energy Certificate (REC) market category represents whether RECs can be generated or not. This applies only to fuel consumption and stationary energy generation technologies. The general term REC is used in this report. Large-scale generation certificates (LGCs) are the relevant type of certificate created by accredited renewable power stations in Australia [2].
ESG Concerns	This category represents the range of Environmental, Social, and Governance (ESG) concerns and opportunities that may arise beyond GHG emissions. These include, but are not limited to, waste, end-of-life treatment, social issues (conflict minerals or human rights), land use, water, and other pollutants.

Ease of implementation	Central to ease of implementation is whether adoption of the technology would interface well with existing mine planning. For example, retrofitting existing infrastructure is generally much easier than entirely new methods.
Cost (CAPEX intensity/OPEX intensity)	CAPEX represents the capital expenditure, and OPEX represents the operational expenditure. Intensity ratings are used as a general guide to the relative expected costs across technologies.
Learning curve	The learning curve category represents how costs are currently expected to change in the future in Engie's view, though this cannot be known with certainty. Learning curves represent changes to the technology and its production methods that reduce costs over time.
Health & safety benefit	This category represents general health and safety risks associated with change from fossil fuel-based default technologies. There may be some considerations for toxicity, flammability, or other concerns. Likewise, there is a possibility of removing risk and making the default technology or process safer.
Decarbonisation Score	We assigned decarbonisation scores as a means of comparing technologies and fuels across multiple criteria. The primary factor for decarbonisation is the relative emissions abatement of a technological substitution, which is central to the decarbonisation score. This abatement is then modulated by a series of other factors as identified by each category for consideration in a table. Each of these categories may then be weighted differently depending on the use case. This culminates in a single number that embodies the decarbonisation impact weighted by other relevant factors. The scores are a weighted average, multiplied by the emission benefit. Technologies that have a positive emission benefit will return a positive number, whereas technologies that emit more than they abate return a negative number. For technologies that are not directly related to an emission benefit (such as batteries), this emission benefit effect is ignored and the decarb score is just a weighted sum of the component factors. The methodology is set out in Appendix B. Factors contributing to the scores are qualitatively discussed in the technology assessments following the heatmap. The scores are general in purpose, highly context dependent and intended to provide an indication of compatibility with zero carbon mining.

TRL and CRI

The TRL and CRI scores are related, as demonstrated in Figure 1. All technologies that are TRL 9, for example, are technologically proven and have been tested or proven to work in the relevant conditions. In contrast, a CRI score is based on the commercial adoption, however, it is related to the TRL as commercial adoption requires technological maturity. Once a technology reaches TRL 9, there will still be significant commercial development required to establish economic competitiveness compared with other technological substitutes.

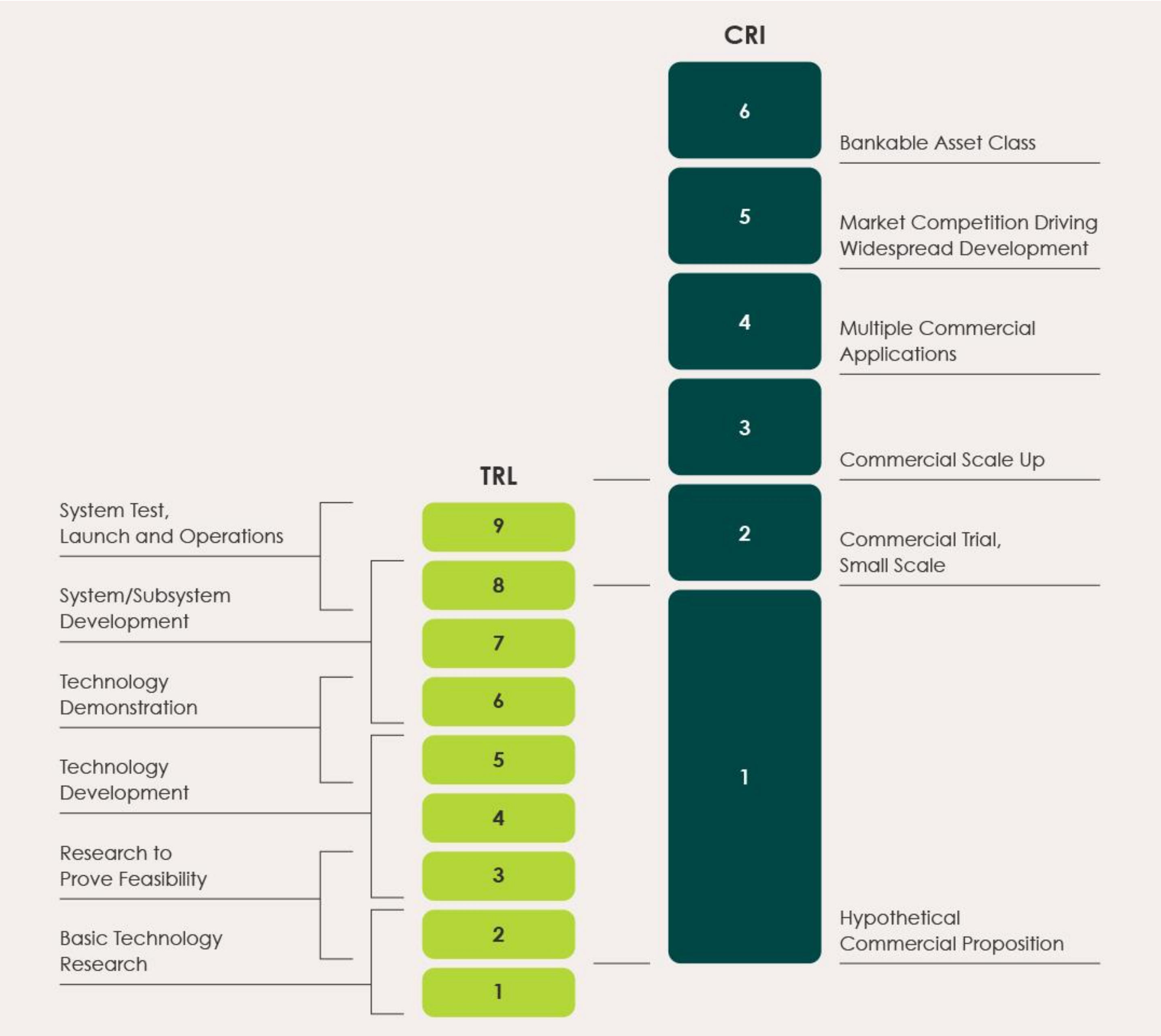


Figure 1: TRL and CRI description, showing the relationship between technological and commercial readiness. Source: ARENA [3].

Fuels: Energy carriers

Given the significant emissions associated with diesel fuel consumption in mining operations[1], achieving zero-carbon mining will ultimately require the use of zero-carbon fuels. As an important energy carrier delivering a critical input to mining operations, a central decarbonisation challenge will involve supplying the same amount of energy with no associated emissions.

Key takeaways

- **Electrification is a leading strategy to achieve decarbonisation**. Direct consumption of electricity is efficient and can be directly sourced from renewable energy generation.
- **Green hydrogen or green ammonia produced with renewable energy is an indirect way of using electricity to important decarbonise fuel (e-fuels):** Indirect electrification through the production of green hydrogen or green ammonia can support processes and technologies that require chemical reduction or some process heat, as well as some storage and transport applications.
- **Technologies and processes inherit risk from fuel:** Fuel consumption inherits the risks associated with the production and sourcing of that fuel. Environmental, technology, supply-chain and safety risks differ but need to be managed with all fuels.

Fuel options: In brief

Some technology solutions require a specific fuel input. However, others may be compatible with a range of fuels that can be substituted to reduce emissions associated with fuel consumption.

Table 2 provides a non-exhaustive summary of available fuel types, which involve varying risks and practical challenges. The use of transition fuels may be required to achieve emissions reductions in the short term before large-scale implementation of zero-carbon solutions are possible.

Table 2: Overview of relevant fuel options

Fuel name	Overview
Diesel	Historically the most common fuel on a mine site, diesel emits a significant amount of CO_2 per kL consumed. Diesel will still be required in the immediate future, however moving to lower or zero-carbon fuel sources is recommended where possible.
LPG	Liquified Petroleum Gas (LPG) with a lower energy content and a lower emissions intensity than diesel, is used in various heating and generation applications due to its commercial availability. Despite its lower emissions intensity, it is still a source of emissions and transition to alternative fuels is recommended to achieve zero-carbon mining.
Green Hydrogen	Green hydrogen is an indirect form of electrical energy, with 'green' describing hydrogen produced from electrolysis where the process is powered by renewable electricity. The major barriers to green hydrogen adoption are primarily commercial rather than technical, with production possible but not yet deployed at scale in Australia at competitive prices. Other forms of hydrogen production (i.e., 'blue' or 'grey') available in Australia produce emissions and are not considered in this analysis.
Natural Gas	Natural gas has a lower emissions intensity than diesel but still contributes significant CO_2 emissions on consumption. Across the value chain, fugitive emissions of methane also occur, which is a potent GHG [4] [5] [6]. Challenges include the need for long-term infrastructure, such as compressors, transmission and distribution pipelines, and companies should consider, and wherever possible avoid, the duplication of infrastructure and risks arising from lock-in to long-term supply agreements.

1 Refer to Figures 47 and 48.

Fuel name	Overview
Green Ammonia	Green ammonia is another form of indirect electrical energy, and generally refers to ammonia produced using green hydrogen and renewable electricity through a Haber-Bosch process.[2] Green ammonia can be combusted in an internal combustion engine (ICE), like diesel, but also has some associated toxicity concerns. It can, however, be a viable decarbonisation fuel if its commercial position improves as expected.
Biomethanol	Biomethanol is sourced from biogenic (carbon neutral) sources. It can be easily manufactured from renewable resources, easily transported and stored in liquid form, and can be readily converted to hydrogen at the point of use or used directly as a clean and low-carbon transport fuel. Potential risks include competition (depending on the feedstock used) with food supply and potential land-degradation implications if adopted at scale. Detailed sustainability analysis and accounting is required.
Biogas/ biomethane	Biogas is produced from the anaerobic (oxygen free) digestion of organic matter. It can be made from a large variety of organic resources, including industrial waste, agricultural waste, energy crops, sludge from waste-water treatment and biowaste (co-digestion or mono-digestion of food waste and other types of biowaste). Biogas can also be upgraded into biomethane, a gas with a chemical composition very similar to natural gas.
Gasoline	Gasoline is the other significant hydrocarbon liquid fuel. Generally, for smaller vehicles, gasoline produces less emissions than alternatives such as diesel, with proportionally lower energy content. While readily commercially available, it is an emission-intensive fuel.
Electricity	Electricity is widely considered the leading medium to achieve zero-carbon mining, with decarbonisation determined by the degree to which an activity, technology, or process can be electrified. Current grid electricity supply is not zero carbon, but behind the meter and market-based solutions mean zero carbon electricity is achievable in many circumstances.
Renewable Diesel/ Hydrogenated Vegetable Oil (HVO)	Renewable diesel or HVO is a biofuel primarily sourced from agricultural biomass such as soybean, agricultural waste and used cooking oil. This fuel is a direct substitute for stationary diesel. Potential risks include competition (depending on the feedstock used) with food supply and potential land-degradation implications if adopted at scale. Detailed sustainability analysis of the supply chain is required. Renewable diesel is distinct from biodiesel. In the Australian retail market, biodiesel contains a blend of diesel and either 5 or 20 per cent of fatty acids from vegetable or animal tallow. In Australia, these blends are called B5 or B20. Not all diesel vehicles are compatible with biodiesel.
Synthetic Diesel	Synthetic diesel (produced through the Fischer-Tropsch process[3]) is a significantly more expensive and commercially challenging process. While technically possible, it will always be more expensive than the direct use of the precursor inputs (such as renewable electricity) required for its production. The emissions intensity of this fuel depends on how it is made. It is possible to produce synthetic diesel from biogenic carbon sources, but this is not yet deployed at scale in Australia, nor at competitive prices.

2 The Haber-Bosch process is an energy-intensive process where hydrogen is chemically reacted with nitrogen in the air to produce ammonia.

3 The Fischer–Tropsch process is a collection of chemical reactions that converts a mixture of carbon monoxide and hydrogen or water gas into liquid hydrocarbons.

Heatmap: Fuels

The first of the heatmaps in this report, Table 4 demonstrates a comparative assessment of the fuels summarised above, outlining their associated emissions factors and a range of environmental, technical, and commercial considerations, which are further discussed below. Table 3 sets out categories that are used in addition to Table 1.

Table 3: Additional heatmap categories relevant to fuels

Factor	Description
Emission factor	Emission factors (EF) are a tool used to calculate the quantity of GHG or marginal rate of emissions related to the consumption of a specific fuel. The emission factor is the prescribed amount of emissions produced per unit of fuel consumed.
GHG on consumption	Represents whether the fuel adds to the carbon cycle at the point of consumption.

Table 4: Overview of relevant fuels for consumption. Technology Readiness Level (TRL) and Commercial Readiness Index (CRI) are based on production technologies and processes, while current and future costs represent learning curve and expected market trends. The Western Australian South-West Interconnected System (SWIS) was selected as a sample electricity grid.

Fuel name	Emission factor	GHG on consumption	Technology Readiness	Commercial Readiness	REC Market	ESG concerns	Current cost	Future cost	Current indicative fuel costs (Note: fuel cost, not cost of generation from fuel)
Stationary Diesel	2.71 tCO_2e/kL	Yes	TRL 9	CRI 6	No	Yes	Low	Medium	132 –146 AUD/MWh[4]
Stationary LPG	1.55 tCO_2e/kL	Yes	TRL 9	CRI 4	No	Yes	Medium	Medium	~76 AUD/MWh[5]
Green Hydrogen	0.00 tCO_2e/t	Negligible	TRL 8	CRI 1	Potentially	Potentially	High	Medium	143 – 238 AUD/MWh[6]
Gas	0.05 tCO_2e/GJ	Yes	TRL 9	CRI 6	No	Yes	Low	Medium	~68 AUD/MWh[7]
Green Ammonia	0.00 tCO_2e/kL	Negligible	TRL 8	CRI 1	Potentially	Potentially	High	Medium	150 – 270 AUD/MWh[8]
Biomethanol	0.00 tCO_2e/kL	Biogenic	TRL 9	CRI 2	Potentially	Potentially	Very high	Medium	546 – 717 AUD/MWh[9]
Biogas/ biomethane	0.01 tCO_2e/GJ	Biogenic	TRL 9	CRI 2	Potentially	Potentially	Very high	Medium	Data not available.
Stationary Gasoline	2.32 tCO_2e/kL	Yes	TRL 9	CRI 6	No	Yes	Low	Medium	149 – 161 AUD/MWh[10]
General grid electricity	0.68 tCO_2e/MWh	Depends on production	TRL 9	CRI 6	Yes	Limited	Medium	Low	E.g STEM price for the WEM -7.7 - 110.0 AUD/MWh[11]
Renewable diesel/ Hydrogenated Vegetable Oil (HVO)	0.00 tCO_2e/kL	Biogenic	TRL 9	CRI 6	Potentially	Potentially	High	Very high	Data not available.[12]
Synthetic Diesel (from biogenic carbon sources)	0.00 tCO_2e/kL	Biogenic	TRL 8	CRI 1	Potentially	Potentially	Very high	Very high	Data not available.[13]

4 Price taken from ENGIE Impact internal references for 2021. MWh is MWh thermal not inclusive of energy inefficiencies. Including 42c/L rebate.

5 Price taken from spot price 28/3/2022 and converted using NGER energy content factor. No forecast price through to 2050. Assumed the same handling costs as for gas consumption. MWh is MWh thermal not inclusive of energy inefficiencies.

6 Price taken from ENGIE Impact internal references, data primarily from CSIRO National Hydrogen Roadmap 2018. 2050 prices forecast to be between 108 and 149 AUD/MWh. MWh is MWh thermal not inclusive of energy inefficiencies.

7 Price taken from ENGIE Impact internal references. 2050 prices forecast to be between 74.52 and 90.98 AUD/MWh. Context is mining and remote operations, inclusive of transportation and handling. MWh is MWh thermal not inclusive of energy inefficiencies.

8 Price taken from ENGIE Impact internal references, data primarily from Casero et al. (2021). 2050 prices forecast to be between 84 and 161 AUD/MWh. MWh is MWh thermal not inclusive of energy inefficiencies.

9 Price taken from CSIRO sources, specifically the Advanced liquid biofuels report (2016) and the Innovation Renewable Methanol (2021, Annex 3). Calculations done internally to convert into correct units.

10 Price taken from ENGIE Impact internal references for 2021. Future prices range between 242 and 397 AUD/MWh in 2050.

11 STEM price taken for WEM as an example. In practice, electricity prices are highly dependent on contractual arrangements and PPAs. Retailers offer different prices, and off-grid scenarios are generally more expensive.

12 Due to the range of energy content factors, lack of liquid market, and inelastic market, prices are not well known.

13 Due to the lack of liquid market, prices are not well known. Fischer-Tropsch fuels are composite of their component costs. Moreover, uncertainty on 'return on energy' of synthetic diesel makes costs difficult to quantify.

Fuel considerations

Emission Factor

The data in Table 4 is based on regulatory, or expected regulatory, emission factors (EF). For Australia, the government-regulated emission factors are available in the National Greenhouse and Energy Reporting Measurement Determination (2008) [7] and are updated annually.

GHG on consumption

While there may be no carbon emissions attributable from a regulatory perspective, they may occur elsewhere in the fuel's lifecycle or have other non-carbon based GHGs. Some fuels, like ammonia, have an emission factor of zero or no carbon content, however carbon dioxide (CO_2) is not the only GHG. There may be other potent GHGs, such as nitrous oxide (N_2O – in the example of high-temperature combustion, albeit rare), emitted that are not reflected in the regulated EF.

The scope of EF should be considered too. From a regulatory point of view, while there may be no carbon emissions attributable to ammonia combustion (Scope 1), these may occur elsewhere in the fuel's lifecycle (Scope 2 or 3).

Similarly, while the combustion of hydrogen releases only water as a by-product, there may be emissions within the method of production. Although green hydrogen is produced with zero emissions, all other methods of producing hydrogen in Australia involve some form of addition to the carbon cycle, such as Steam Methane Reforming (SMR) that uses natural gas as feedstock. While current regulations consider hydrogen to have no GHG emission on consumption, it could be the case that non-green forms of hydrogen (and therefore ammonia) are regulated in the future with an EF representative of embodied emissions.

Where a fuel's carbon content is sourced from the biosphere (such as biomethanol, biodiesel and wood), it can be considered net-neutral. These are biogenic emissions, where carbon released on consumption is released back to its original source, the carbon cycle [8]. However, embodied within some land-based fuels are non-biogenic emissions that add to the carbon cycle beyond what is subtracted, through land-use practices [8]. Typically, it is uncommon for a biofuel to be completely zero emissions across its lifecycle.

Technological readiness

As indicated in Table 4, there are well-understood and technically mature chemical processes for producing liquid fuels such as hydrogen, ammonia, methanol, and synthetic diesel. However, electrolysis and long-term hydrogen storage have not yet been deployed at the scale required to meet the expected hydrogen demand.

Most hydrogen is currently produced through the carbon-intensive SMR process [9]. Although small-scale electrolysis is well understood, production data from the International Energy Agency (IEA) in Figure 2 shows minimal green hydrogen production in 2020 with growth expected in the future [10].

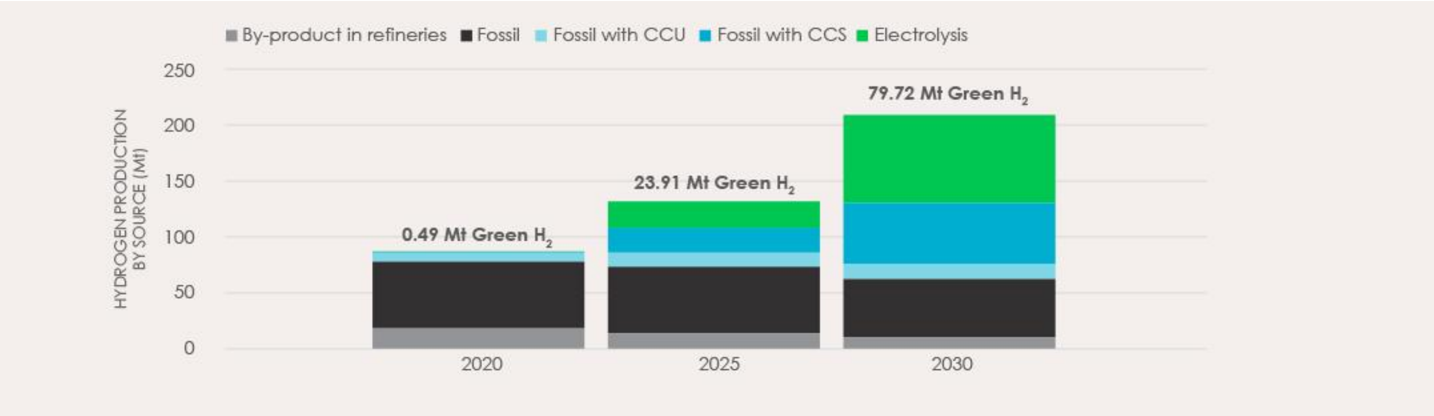


Figure 2: Global Hydrogen production by source. Data from the International Energy Agency's (IEA's) Net-Zero Scenario. Note the current green hydrogen production compared to fossil-based hydrogen production.

A key question is at what point green hydrogen infrastructure can be commercially viable at the significant scales required. There are corrosion limitations on blending hydrogen for transportation through existing gas pipelines (roughly 7 per cent H_2/CH_4 on an energy content basis [11]), and hydrogen liquefaction and regasification terminals do not yet exist at scale.

Commercial readiness

The commercial and economic position of each fuel is where significant differences emerge. In particular, the economics of hydrogen and synthetic diesel currently lag the fuels they are to displace and neither have been commercially proven at the scale required without significant state intervention.

While there are a rapidly increasing number of green hydrogen projects planned, significant growth in production scale is needed to become cost-competitive with other fuels. These 'learning rates' are common in the adoption of new technologies.

With high commercial readiness, electricity provides more certainty around commercial viability. The relative cost per unit of green electrical energy is steadily decreasing due to the increasing supply of near-zero marginal cost electricity from solar and wind projects. Where possible, however, hydrogen and renewable energy may offer a strong economic advantage if they coexist. Paired with electricity, the production of green fuels can also provide an alternative form of energy storage, which may be ultimately cheaper than shorter term storage options such as batteries.

Limits on electrification are imposed by the physical requirements of equipment, such as high-temperature heat processes. It may be technically possible to reach high temperatures with electricity, but the marginal increase in equipment cost may be so large that traditional combustion technologies, with more expensive green fuels, may be a more viable zero carbon option. Therefore, the context of fuel usage is key to its viability.

Renewable Energy Certificate (REC) markets

Many jurisdictions offer a certification mechanism to certify energy consumption as ‘renewable’ or ‘green’ [12]. In Australia, the relevant certificate is the Large-scale Generation Certificate (LGC), which is a regulatory tool to incentivise the construction of renewable energy. One LGC can be created for each megawatt-hour (MWh) of eligible energy produced, and LGCs are required to be obtained and surrendered by certain electricity users and retailers [13]. Even though the electricity consumed is a non-zero emission source of generation, as for grid electricity overall, a consumer may purchase and surrender LGCs from a renewable energy generator to match total electricity consumed with green electricity production. While there is no change at the point of consumption, there is a reduction in attributable emissions.

This certification approach has potential for many forms of fuel consumption, including certificates to represent green hydrogen or green methane consumption. Such work is being conducted in Australia by the Clean Energy Regulator (CER) to develop a Guarantee of Origin (GoO) certification scheme for hydrogen [14].

ESG concerns

Environmental discussion of fuels has so far focused on emissions associated with consumption. While emissions are an important ESG issue [15], there are many other ESG considerations with existing and emerging fuels that must be acknowledged in the decision-making process so that risks are well managed.

Water and food are the two most important commodities and they will be adversely affected by the physical impacts of climate change [16]. Production of biofuels [17] and green hydrogen [18] may place additional pressure on natural resources, as biofuels may compete directly or indirectly for land for food resourcing, and both processes require large volumes of fresh (or desalinated) water. This is particularly true in the mining context, where water resources are expected to be negatively impacted directly by climate change in many Australian mining operations.

The lowest risk fuel solution from an ESG perspective is electricity, due to its ability to rapidly decarbonise. Most electricity is currently generated from carbon-intensive sources but is trending to zero carbon generation over time. Other ESG concerns such as technology supply chain issues and the intensity of land requirements must, however, be considered when sourcing zero-carbon energy (see Figure 26, under *Stationary Energy*).

Current & Future cost

The cost of variable renewable energy (VRE) technology continues to trend down due to a combination of scale and learning, while traditional liquid fuels have achieved maturity with little room for improvement, and prices largely follow international commodity markets.

Fuels produced from electricity, such as green hydrogen and ammonia, will improve in cost as the cost of renewable energy and electrolysers continues to decline. Each layer of transformation, however, from electricity to hydrogen to ammonia, adds unavoidable costs and thermodynamic inefficiencies. **The general rule is electricity will trend to, and remain, the cheapest form of energy per unit in the long term. However, the cost of electricity will be influenced by the availability of renewable energy resources and energy storage.**

Traditional liquid fuels are available on demand and the time of consumption has limited impact on cost. With daily and seasonal changes in the availability of VRE, the cost of energy consumption is influenced by its availability. To consume renewable energy outside its time of generation requires significant storage infrastructure. While this technology exists and large-scale battery technology is following a similar declining cost trend to wind and solar, it remains a potentially significant additional cost that increases the overall cost of electricity consumption. As the proportion of VRE generation grows and reliability requirements increase on a grid, the storage requirements begin to increase disproportionately. Storage technologies are discussed further in the next section.

Stationary energy

Summary

Mines are large energy consumers, particularly with respect to gas and diesel fuel. While some processes require a specific fuel input, technology developments mean others are increasingly compatible with alternative lower emissions energy sources.

Decarbonising stationary energy is important for both its immediate emission reduction potential and its ability to unlock future reductions. Stationary energy is a significant contributor to the cost and energy requirements of a mine; for some commodities it can exceed 60 per cent of total energy requirements [19].

In this context, stationary energy is the energy embedded with the generation and consumption of electricity, excluding mobile applications (transport and material movement are considered in the following chapter, although stationary energy will be the source of energy for most electrified means of transport as these technologies develop). While stationary energy generally includes the production of process heat, given the importance of electrification for decarbonisation strategies the focus in this context is on and off-grid electricity generation.

Scaling and achieving reliable, sustainable, and affordable electricity generation will be required in any decarbonisation journey. As the electrification of other mining activities, including material movement, progresses, there will be a greater imperative and advantage for decarbonised electricity through the implementation of renewable energy and energy storage technologies.

It is important to note that any mine-level solution will be a customised one, that incorporates a range of technologies. The optimised solution for a particular site will be specific to its context, including wind and solar resources, location and demand profile. It is also important to note the rapid improvements in technology, which are seeing renewable penetration rates rapidly increasing as developers and energy integrators learn how to apply new technology.

Many enabling technologies are well developed and commercially available. Wind and solar are the two main forms of renewable electricity generation and lithium-ion (Li-ion) batteries are the most versatile available for shorter-term storage applications (Figure 3 and Figure 4). Geography and climate play a significant role in the determination of available renewable resources and technology selection should also consider the varied risks and characteristics within different battery families.

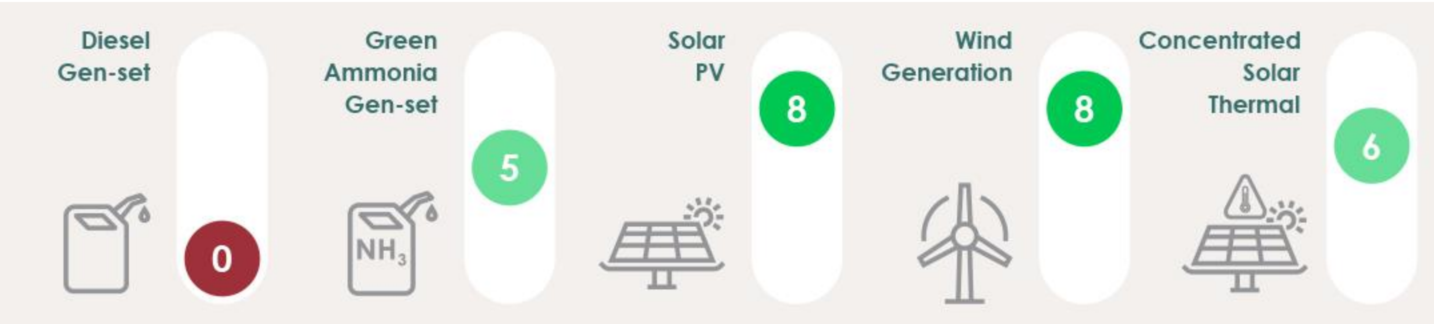


Figure 3: Summary of decarbonisation scores of key energy generation technologies

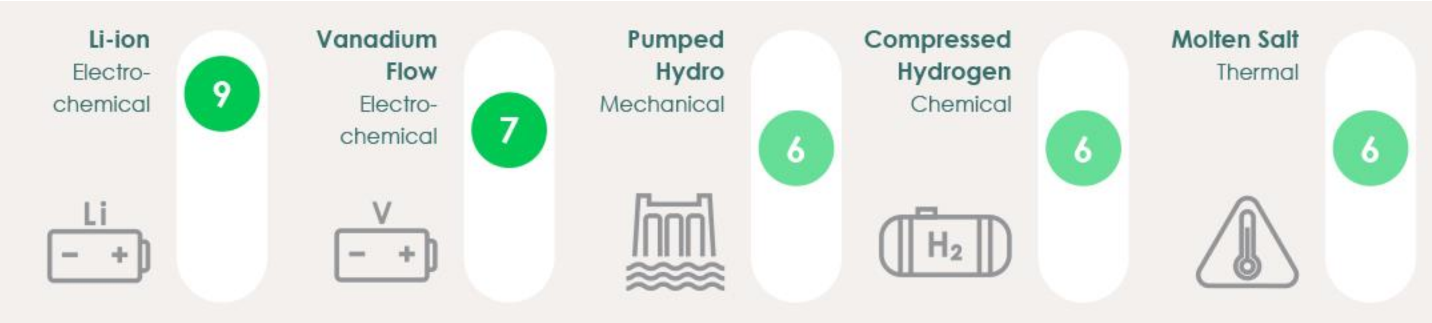


Figure 4: Summary of decarbonisation scores of key energy storage technologies

Technology insights

- **Renewable energy leads decarbonisation impact:** Oversized solar installations and well-located wind generation can deliver low-cost, zero emissions electricity and charge batteries for night-time consumption.
- **Energy storage offers broader solutions:** Modularity, energy density and declining costs make Li-ion batteries suitable for most applications, with vanadium flow batteries gaining traction for longer term storage applications.
- **Green hydrogen and green ammonia gain momentum:** Improving production processes are increasing access to these energy sources, which are suitable for critical mining and processing needs, including chemical reduction and process heat, as well as storage and transport applications.

Practical considerations

- **Focus on stationary energy first:** To address a large part of the immediate decarbonisation challenge and create opportunities for ongoing electrification of other activities.
- **Invest in energy storage as an enabler:** For power quality and flexibility, delivering on-demand integration and dispatch of renewable energy.
- **Connect and/or build network connections:** With neighbouring grids and generation assets, to share costs in creating geographic and technology diversification and reducing outage risks.

Stationary Energy: electricity essentials

Electricity is a highly fungible fuel type that can be consumed by a wide range of technologies and equipment. Complex interactions and contextual factors play a significant role in enabling decarbonised stationary energy solutions for mine sites. Within the context of power generation, the combination of underlying physical processes can vary significantly in complexity. The key points that factor into decarbonising power generation are discussed below.

While many of the technical limitations and definitions are discussed elsewhere, there are several high-level considerations for optimal electricity supply in the context of a zero-carbon mining operation.

Competing demands of reliability, sustainability, and affordability determine the ultimate composition of power generation.

Figure 5: Reliability, Sustainability, and Affordability; critical elements of electricity decarbonisation

Transporting electrical energy: through distance and time

Moving energy over distances and storing it over a length of time involve inefficiencies. How well these inefficiencies can be managed will determine the ease of deep decarbonisation.

Transporting over distance: poles and wires

Electricity needs to be moved from where it is produced to where it needs to be consumed. The inefficiency of electricity transport is proportional to the distance the energy must travel. The construction and management of poles and wires is relatively simple, however, it becomes more complex as the electricity network grows and higher volumes of variable renewable energy (VRE) are installed. Given the scale of renewable energy required for some operations, economic volumes of renewable resources may be some distance away from the mining operation, as shown in Figure 6.

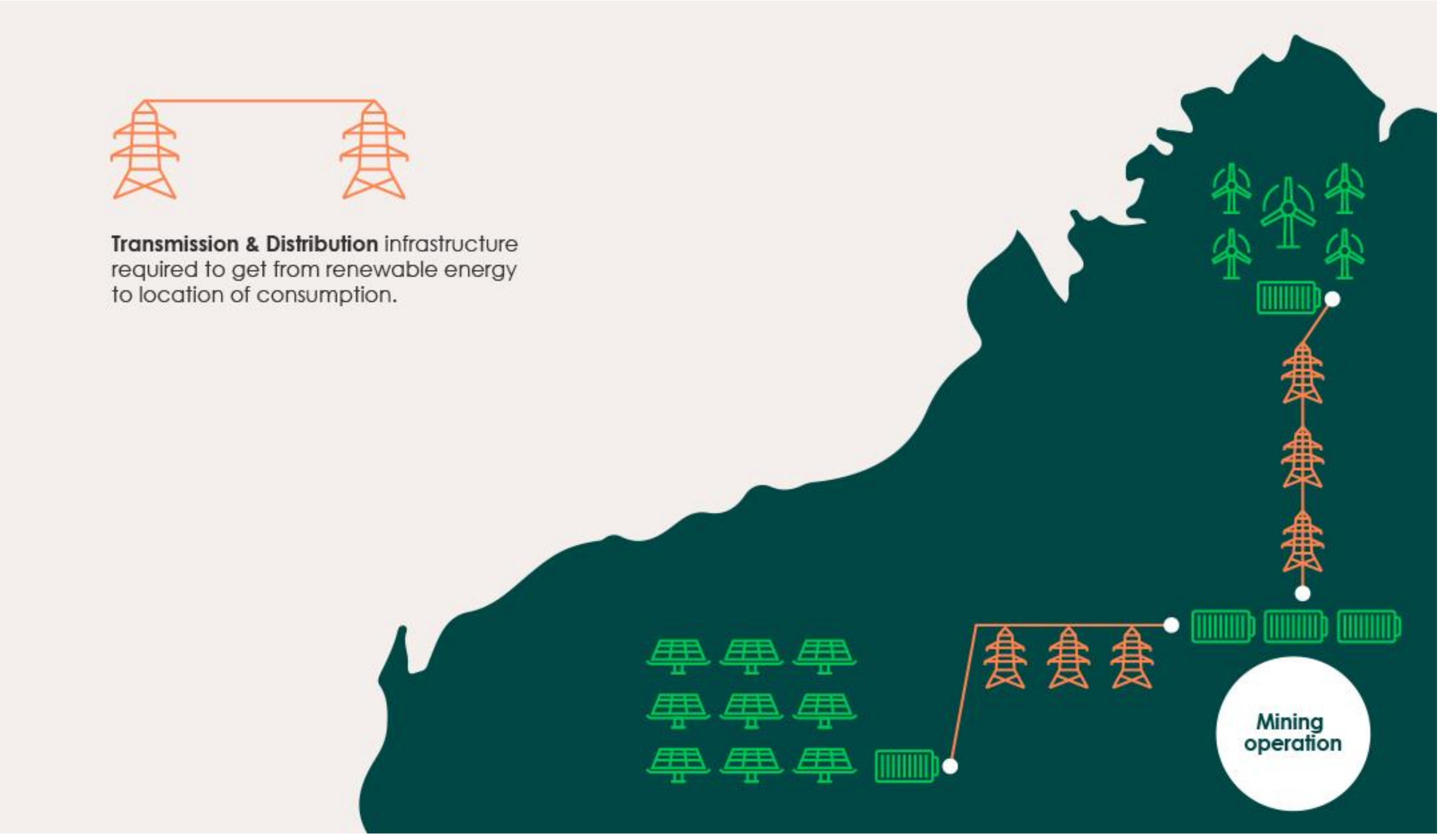


Figure 6: How renewable resources can be a significant distance from consumption, requiring investment in transmission and distribution infrastructure

Transporting over time: energy storage

Energy consumption needs to be matched with energy generation over time. Storage allows generated energy to be stored for later consumption and provides a critical component of grid management. The total energy (MJ, or MWh) and power (rate of energy supply, MJ/s, or MW) are the two key parameters of focus in energy storage. As with transporting energy over distance, storing energy for periods of time also incurs an inefficiency. The key is to store energy and mitigate the impacts of both variability and intermittency of VRE. These effects are demonstrated in Figure 7 with stylised versions of wind and solar power.

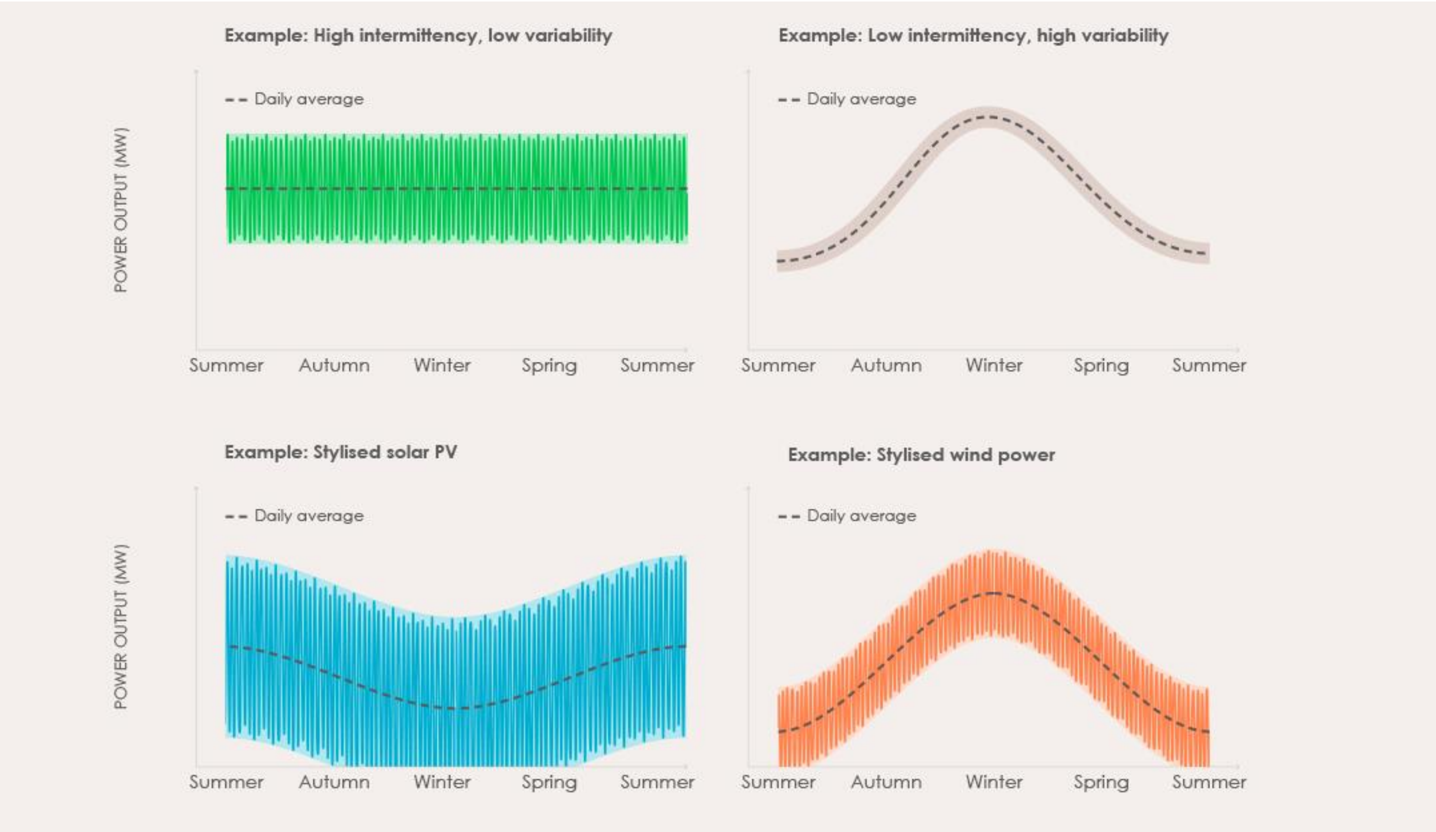


Figure 7: The effects of intermittency and variability on power output of VRE. In this example, both solar and wind power have some variability and intermittency in generation

In this context, ‘battery’ is a generalised term, there are a wide range of battery options that, like the energy generation technologies, are highly context dependent. There are two general categories of storage that frame how storage is important to reliability:

Short-term storage

Grid management is increasingly required as VRE penetration increases to manage intermittency. To maintain power quality, short-term storage is required to provide inertia [20], which is analogous to grid stability in this context. Many technologies can be used, and the purpose of short-term storage is largely to provide power quality services and mediate the intermittency of VRE supply. This is particularly true in managing generation such as solar and wind power.

Long-term storage

Beyond intermittency, variability represents seasonal changes in VRE generation. This is overlayed on top of intermittency and focuses more on aggregate volumes of energy as opposed to momentary power outputs. Long-term storage in a decarbonisation context aims to ensure the availability of electricity if there is a period without wind and diminished solar resources.

Understanding how these two forms of energy storage interact and overlap is critical to progressing the decarbonisation of mining operations. If mines are connected to a regulated network, such as the National Electricity Market (NEM) or South West Interconnected System (SWIS)[14], the need for both forms of storage is diminished as a large electricity network will likely have the power quality services required.

Integrating variable renewable energy

Grid management is complex when managing multiple sources of VRE and maintaining power quality. Generally, electricity is either consumed or wasted – this means generation must match consumption. Energy storage technologies avoid this by consuming electricity and storing it in other energy means (such as chemical, electrochemical, or gravitational energy). Energy management strategies can be seen in Figure 8 where the impacts of supply change and demand response (DR) can be seen for a stylised grid demand curve.

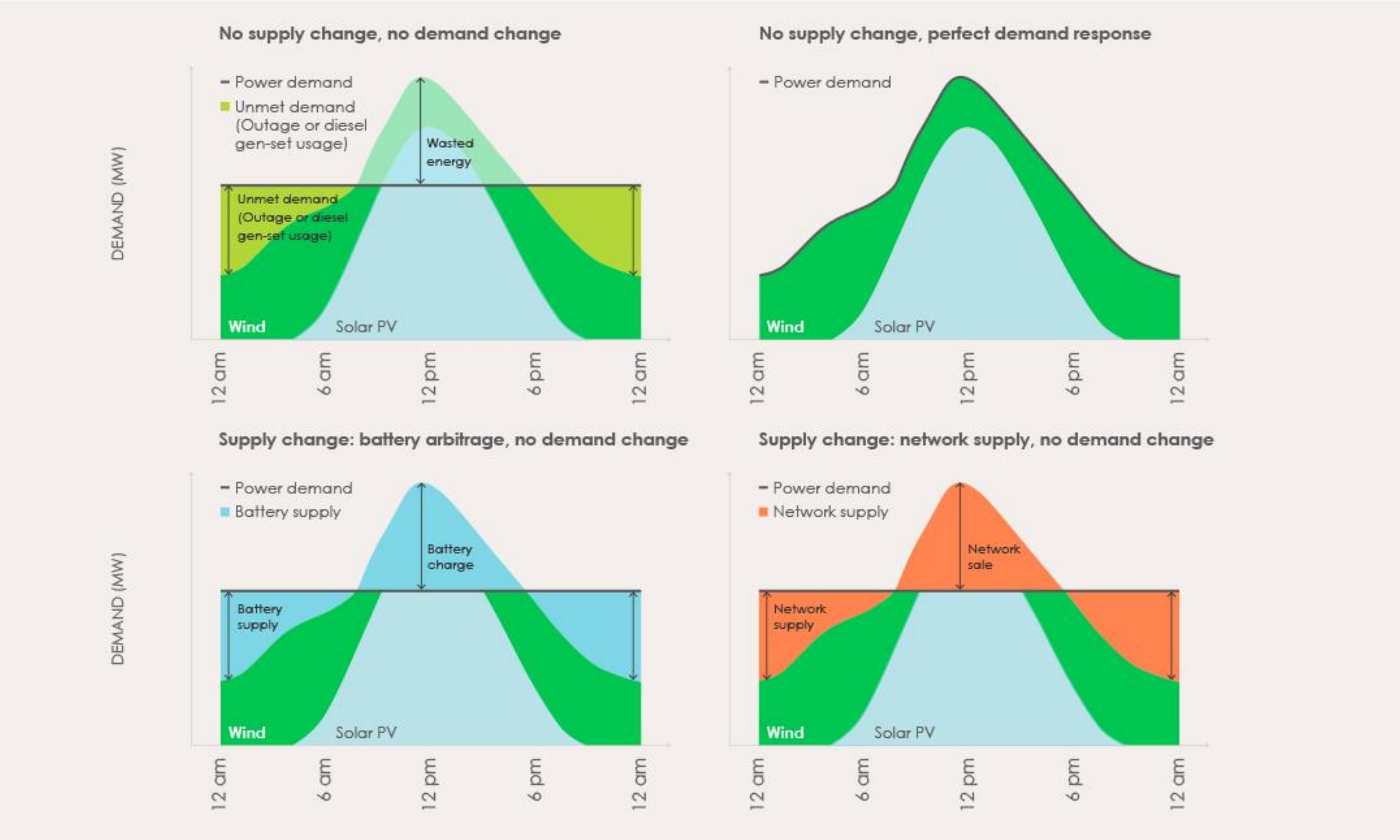


Figure 8: Energy management strategies. *Top-left:* Wasting energy (curtailment) and meeting unmet demand with gen-sets. *Top-right:* Perfect demand response, matching consumption (and therefore production) with available energy supply. *Bottom-left:* Utilising batteries to supply unmet demand with previous battery charge. *Bottom-right:* Utilising the network by buying and selling unmet demand and excess generation, respectively.

14 Technically the NEM is the market, and the SWIS is a regulated network. The SWIS is within the Wholesale Electricity Market (WEM) within Western Australia. The market rules across these two major jurisdictions are different.

Diversity in power supply

Stand-alone technologies are discussed below, however, there will likely be no single technology solution that is used in isolation. **Each technology carries its own set of risks and implementation considerations, using a diverse combination can help to offset or overcome them.** Given the need for power quality, a strategic hedge of power supply is required.

Early inroads into decarbonising electricity generation will be easily feasible while supporting reliability, sustainability and affordability. As VRE penetration increases, it becomes more challenging to maintain the reliability and affordability of electricity supply, but rapid improvements are being made in this area. Anecdotal evidence indicates that since about 2018 renewable penetration levels for mine sites trying to decarbonise their generation has increased from expectations of 20–30 per cent to around 50 per cent at present, with various new projects targeting levels approaching 80 per cent or more. Diversifying electricity supply enables deep decarbonisation (greater than 80 per cent) of islanded grid systems. Completely zero-carbon electricity over a timescale of years at this juncture remains challenging in remote systems without using significant long-term storage or e-fuels such as green hydrogen, however, this will change with continued technology developments.

Diversity in power demand

Demand response, or load management, is another method of electricity grid management that can enable deep decarbonisation of electricity supply. In this case, DR matches demand to the availability of electricity, as demonstrated above in Figure 8. Load shifting and flexibility in the context of mining and processing operations means throttling, or managing production, to be in-line with the power availability. This can be a cost-effective way to enable higher penetration of renewables, by shifting activities to peak sunlight hours, for example. Such practices are common, with the management of energy-intensive mills being an example of where processing is matched to available electricity, such as in (OZ Minerals). In line with the distinction between short-term and long-term storage, DR can support both intermittency and variability of VRE. Seasonal and momentary production regimes can be implemented to ensure that emission-intensive power generation is used as a last resort. DR can enable both reliability and sustainability, though potentially at the economic cost of production throughput.

Power networks: Access to services and risk mitigation

Within most regulatory contexts, there is a formal distinction between off-grid and on-grid power supply. In this context, an off-grid mine would be an operation with its own means of supply and grid maintenance. Alternatively, there may be some edge-of-grid or grid-connected power. Each of these arrangements represents a degree to which a facility or site has access to a power network. From complete integration into a network, like the NEM or SWIS, through to a completely islanded grid, there are costs and benefits to both off-grid and grid-connected arrangements. Figure 9 shows the continuum of grid connection.

As the cost of renewable electricity trends downwards, the bulk of the cost of power will be from maintaining power quality. A challenge is that connection to regulated networks implies significant network charges and regulated costs. Off-grid solutions can be regulatory independent and avoid these regulated costs. However, these off-grid arrangements typically mean less efficient capital, as power and storage are often over-procured to independently maintain power quality.

Participation in an electricity network means more efficient capital allocation but increased regulated costs as power quality responsibilities are shared. Importantly, as the VRE generation fraction increases so too does the need for frequency control, black start, and other ancillary services. While network charges may be costly, so too will poor power quality on the performance of a mine.

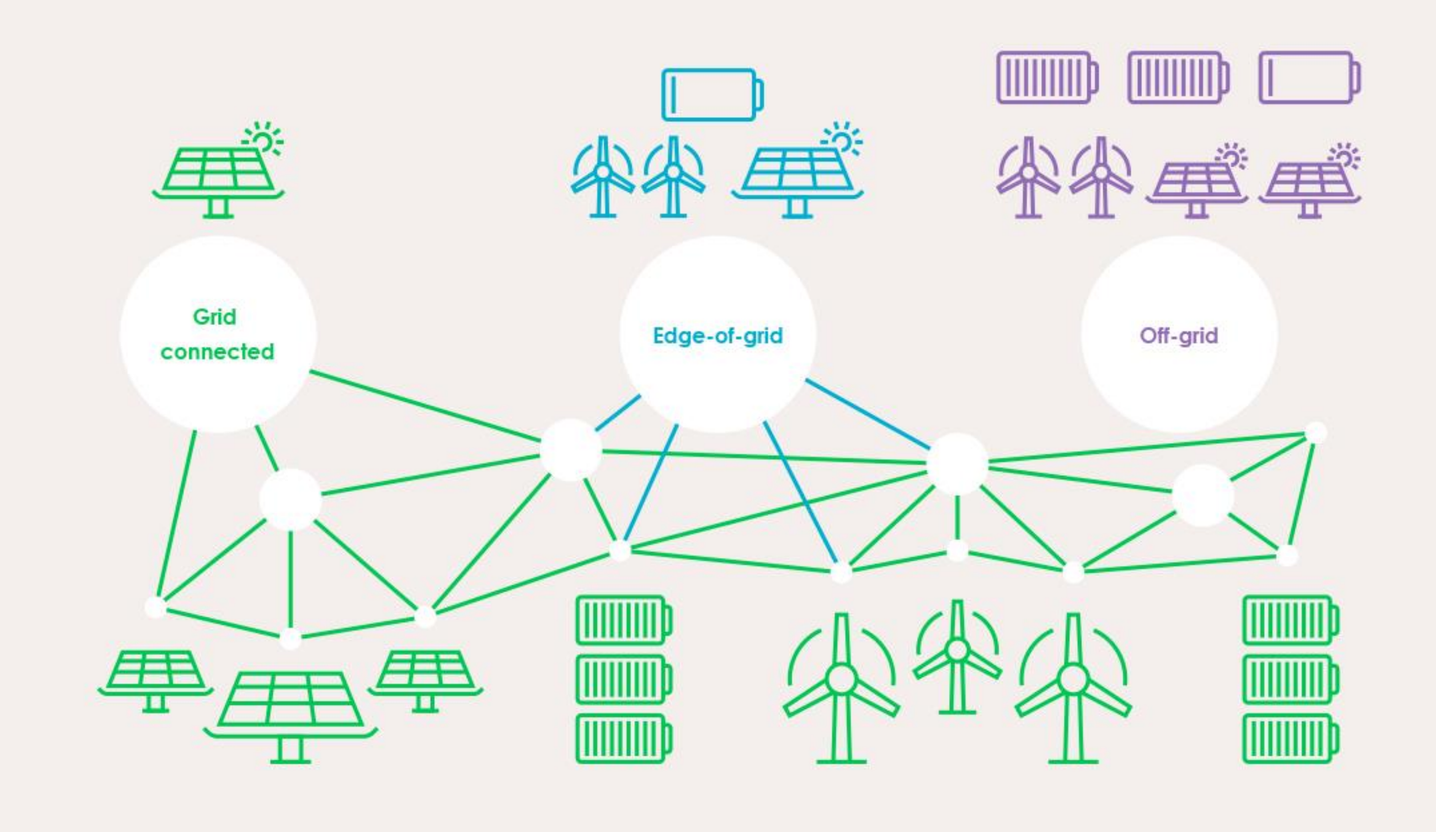


Figure 9: Spectrum of network/grid connection. The greater the grid connection, the greater the sharing of renewable resources and power quality services.

For many mines within an Australian context, connection to the SWIS or the NEM may be unfeasible due to current regulatory structures and distance. However, regulated networks are not the only type of network. It would be reasonable to collaborate with nearby mines and industry to set up multi-party networks, ensuring power quality for multiple stakeholders.

Developing a network for a single mine may be uneconomic but working with stakeholders will reduce the overall cost per participant, improving power quality for all involved. While these parties may be competitors, strategic cooperation will benefit operational costs of all parties.

Acceleration of on-grid decarbonisation

The emissions associated with electricity generation are somewhat unique as they are one of the few types of emissions that can be both indirect, and included in reporting liability. The consumption of electricity itself has no direct emissions associated with it as there is no combustion. Emissions are ascribed through their generation, which will be Scope 1 emission at the point of generation but Scope 2 if it is procured externally by an operation.

Enabled under the Australian Large-scale Renewable Energy Target (LRET) [21], Large-scale Generation Certificates (LGCs) allow for the green rights of power to be traded. Surrendering LGCs is required in most circumstances for power to be claimed as green in Australia. This is a type of regulated REC – a financial instrument used in decarbonisation strategy.

LGCs can only be surrendered (claiming the power as 'green') for Scope 2 emissions, not for Scope 1. This means that the three methods to achieve zero carbon electricity are either:

- **Generate and consume renewable energy behind the meter**: Without the need for LGC generation or procurement, clean power is consumed and reported as behind the meter generation of renewable energy.
- **Generate and surrender LGCs**: The construction and registration of LGC generating infrastructure, such as wind or solar power. Maintain operational control of renewable energy infrastructure, generate LGCs and surrender LGCs to claim green power.
- **Procure and surrender LGCs**: Purchase electricity from an external provider, then procure and surrender LGCs proportional to the electricity volume consumed. This is typically bundled through a green-power Power Purchase Agreement (PPA).

Technology in brief: Forms of energy generation

Energy generation technologies are not mutually exclusive and can be complementary in nature. Solar photovoltaic (PV) and wind power will play leading roles in the decarbonisation of electricity generation in mining operations, with their variability meaning they will need to be paired with energy storage technology to deliver dispatchable power and deep decarbonisation.

This section considers the most common technologies applicable to Australian mining operations.

Solar PV

Solar irradiance is converted directly into electrical energy using the photovoltaic effect. With no moving parts (except when sun-tracking), solar panels convert sunlight into electricity during the day. While there are many types of materials that convert sunlight into electricity, the most common type is the mono-silicon solar cell.

Figure 10: A photovoltaic solar array

Pros:

- Negligible operational cost, and the marginal cost of electricity is also close to zero.
- No moving parts (except when sun-tracking) and negligible maintenance.
- Rapidly decreasing costs of construction and will continue to decrease.
- Modular and scalable so projects can be increased in size easily.
- Generates LGCs.
- No health impacts during operation or liquid fuels required.
- Commercially and technically developed.
- Requirements align with most Australian mining contexts.
- Low and decreasing levelised cost of energy (LCOE) (See Table 6).

Cons:

- Non-synchronous generation, which heightens the difficulty of grid integration.
- Variable and intermittent generation, requiring storage for deep decarbonisation.
- Significant grid management activities required.
- Land-intensive, generation is proportional to the area used.

Wind power

Moving winds can be converted into electrical energy directly through rotating wind 'turbine' generators. Turbines are being built larger than ever before, with the offshore turbines now exceeding 16 MW, with rotors of over 220 m in diameter [22]. Wind is a renewable resource that generally operates day and night, but it can have greater seasonal variability than other renewable resources. In Australia, wind and solar power are often inversely correlated, meaning that when the wind is not blowing it is sunny, and during sunset or at night, wind resources are available. Furthermore, when the wind is not blowing onshore it can be blowing offshore, and vice versa.

Figure 11: Example of a wind farm, an array of turbines generating electricity

Pros:

- Negligible operational cost (excluding maintenance).
- Rapidly decreasing capital costs.
- Generates LGCs.
- No health impacts during operation or liquid fuels required.
- Commercially and technically developed.
- Typically generates for a greater portion of time than solar energy.
- Low and decreasing LCOE (See Table 6).

Cons:

- Non-synchronous generation.
- Variable and intermittent generation, firming is required for deep decarbonisation.
- Very land-intensive, generation is proportional to area used. Need to consider biodiversity impacts. However, land can be concurrently used for other purposes such as pasture.
- Fixed location once installed, and generally longer payback periods than solar PV due to CAPEX, partly offset through higher capacity factors.
- Can be logistically complicated to transport turbine materials such as blades to location, which can ultimately be a limiting factor.

Concentrated solar thermal (CST)

Concentrated Solar Thermal (CST) directs solar energy via a series of mirrors or 'heliostats' to heat materials such as molten salts or water/steam to high temperatures. That heat is then delivered to a multi-hour (typically 12-16 hours) thermal energy storage (TES) system. The stored heat is then used to power a turbine for electricity generation or directly used for process heat applications. The TES can allow for up to 16 hours of continuous power generation.

The optimal CST system size, assuming a steam turbine for power generation and 12–16 hours of storage, is between 50 MW and 200 MW. This sizing and storage configuration delivers the lowest LCOE across all forms of long-duration, (10+ hours) renewable energy storage systems. This technology is therefore likely only applicable to larger mines with high energy demands.

Figure 12: Concentrated solar thermal example being piloted by Rio Tinto on a mine site in California

Pros:

- Lower operational cost than fossil fuel applications.
- Development of CST can also provide thermal energy for high-temperature processing applications as it is a source of heat.
- Thermal storage capacity of up to 16 hours can be built into the system so CST can provide 24/7 operation much of the time as well as ancillary grid support services.
- As the thermal storage capacity increases, the LCOE decreases, such that CST systems with 12 or more hours of storage have the potential to deliver lowest LCOE of all renewable energy storage technologies.
- CST plants can be equipped with a back-up heater providing the opportunity to use spilled renewable energy, ensuring a reliable power supply.
- Under later stages of commercial and technical development with progress and decreasing cost of supply expected.
- Synchronous generation so allows for easier grid integration.
- Generates LGCs.
- Irradiance requirements align with most Australian mining contexts.

Cons:

- Moving parts impose some maintenance costs.
- Technology is not as modular as solar PV and has to be sized initially.
- Land-intensive, generation is proportional to area used.
- Some technologies may have lower social acceptability than PV and wind.
- Not currently deployed in Australia (although growing international applications).
- High but decreasing LCOE (See Table 6).

Liquid fuel gen-sets

Diesel generators are the default source of electrical power for most small-to-medium mining operations. Liquid fuel generators, or gen-sets, are reciprocal engines like the internal combustion engine (ICE). Though typically powered by diesel, generators are often fuel agnostic. Depending on fuel type, equipment quality and design specifications, many fuels can be used in liquid fuel gen-sets with minor or no adjustments.

Figure 13: Diesel generators using reciprocal engines to convert chemical energy into electricity

Pros:

- Low capital cost.
- Synchronous generation enables greater grid stability and ease of integration.
- Short start-up time and can be turned on and off easily.
- Modular and scalable so projects can be increased in size easily.
- Highly developed and secure technology and can work with a range of fuels.
- Weather and climate independent.
- Low land intensity and takes up minimal room.

Cons:

- Inherits logistics and pricing risks from fuel, with most liquid fuels associated with high GHG emissions.
- High and volatile liquid fuel prices.
- Operational cost for fuels is high and location dependent.
- Ancillary liquid fuel storage and supply logistics required.
- Does not scale to large energy production without significant increases in cost.
- High and stagnant LCOE (See Table 6).

Closed-cycle gas turbine (CCGT)

Gas turbines are efficient combustion machines that turn chemical energy into electricity. They are typically more efficient than many of the traditional ICE reciprocating engines in base load applications, but typically less so when applied to pulse loads to balance variable renewable energy loads. There is a greater range of engine architecture within gas combustion than within ICE, with associated differences in efficiency. The form chosen in this analysis is the CCGT, as opposed to Open-Cycle Gas Turbine (OCGT) or reciprocating engines.

Figure 14: An example of a large-scale CCGT

Pros:

- Synchronous generation and significant inertia provided help grid stability.
- Modular and scalable so projects can be increased in size easily.
- Highly developed and secure technology.
- Short-to-moderate start-up time enables grid supporting services.
- Weather and climate independent and highly reliable.
- Low land intensity and takes up minimal room.
- Low to moderate LCOE (see Table 6), subject to location-dependent fuel price.

Cons:

- Moderate capital cost (see Table 6).
- Designed for larger scale energy consumption, less modular in application and less flexible in operation than some battery technologies to accommodate variable renewable energy.
- Inherits risks from fuel, with most gaseous fuels associated with significant GHG emissions.
- Switching to green hydrogen may require significant retrofitting (due to hydrogen corrosion and leakage) for complete decarbonisation.
- Operational cost for fuels is medium to high and location specific.
- Significant gas infrastructure required for supply which often carries contractual take-or-pay risks.

Biomass generation and bioenergy

Biomass generation is a type of bioenergy, a form of renewable energy generated from the conversion of biomass into heat, electricity, biogas and liquid fuels. Biomass is organic matter derived from forestry, agriculture or waste streams available on a renewable basis. It can also include combustible components of municipal solid waste.

When organic material decomposes within a landfill it produces methane, a greenhouse gas 28 times more potent than carbon dioxide. However, anaerobic digestion can provide renewable energy from organic feedstocks and can support significant emissions reduction by diverting organic waste from landfills. Anaerobic digestion is a highly flexible technology with the ability to produce renewable gas, heat, electricity or fuels and importantly, can provide baseload or dispatchable generation as well as provide energy storage potential.

Figure 15: An anaerobic digestion facility at the Richgro site in Jandakot, WA (image courtesy of Delorean/Richgro)

Pros:

- Flexible technology able to produce renewable gas, heat, electricity or fuels.
- Baseload and dispatchable energy generation potential, not intermittent generation like solar and wind.
- Generates LGCs, when producing renewable electricity.
- Commercially and technically developed.
- Moderate LCOE (See Table 6).

Cons:

- Scale may be a constraining factor for deep decarbonisation.
- Continuous feedstock supply is required to generate energy outputs.
- More complex processing infrastructure as compared to other technologies (e.g. solar, wind, batteries) and requires a more hands-on approach to operating the plant.
- Fixed location once installed.

Technology in brief: Energy storage

Energy storage is a critical determinant in the ability to decarbonise mining operations, particularly in edge-of-grid and off-grid contexts, as it allows the use of stored zero-carbon energy at times when wind or solar is not available to meet instantaneous demand. Uptake may also be driven by the desire to increase the levels of low-cost renewable energy in the energy mix, combat the intermittency and variability of some renewable energy types, such as wind and solar, and address the inflexibility of some forms of energy demand.

Relevant types of energy storage

There are several types of energy storage technology, each with different characteristics. Within all, there is a form of potential energy stored that can be converted – with some form of efficiency loss – to another form of energy on demand. High-level groups of energy storage technologies are outlined below.

Electrochemical

In an electrochemical battery, the chemical composition of the material allows for transfer and storage of energy. Generally, the chemical reactions are reversible. Ion batteries such as Li-ion, lead-acid, nickel-metal hydride and flow batteries are electrochemical cells. The chemical composition is often complex but bespoke, leading to a range of uses, materials, and characteristics. Potential energy is stored as chemical potential energy.

Mechanical

Mechanical batteries store energy in various forms, for example as an elevation of mass such as hydropower, which generates energy from water when it moves from one height to another. Other forms of mechanical storage such as flywheels store energy in ultra-low friction spinning masses. In this form of technology, energy is stored in gravitational, kinetic, tensile or other forms of physical energy.

Chemical

Chemical batteries traditional fuels, in that energy is stored within the chemical bonds of liquids or gases. Whether it be diesel, methane, biofuels, hydrogen or other chemicals, energy is stored chemically for later consumption. Generally, energy is recouped through the process of combustion in traditional machines but can also be extracted through electro-chemical processes, such as the use of hydrogen in a fuel cell electric vehicle (FCEV).

Thermal

Thermal storage stores heat in a body, whether it is a liquid, gas, or solid. Examples include molten salt storage where salt is heated to high temperatures and melted. The equipment is well insulated to avoid heat loss and stored heat can be used to directly heat other equipment or power steam turbines to generate electricity.

Electromagnetic

Electromagnetic batteries work differently, storing electrical potential energy between two plates, or terminals. Examples of electromagnetic batteries include capacitors. Generally, these are low volume but high capacity and have niche applications in grid management where high power is required for a very short time.

The following energy storage technologies are applicable to Australian mining operations.

Lithium ion

The most prolific energy storage technology currently on the market, Li-ion batteries are advanced electrochemical cells that have applications on a range of scales. The Li-ion battery is a family of battery types with many sub-technologies that impact the cost and performance of the battery. Li-ion batteries are suitable for power and energy applications from a range of minutes to hours of discharge.

Figure 16: Li-ion batteries used on solar farm

Pros:

- High round-trip efficiency: 90–96 per cent.
- Good energy and power density.
- Low self-discharge: <5 per cent per month.
- Low maintenance requirement and fully self-enclosed.
- Long cycle and calendar life – 3,000 to 5,000 full cycles and many years of life.
- Significant benefits from modularity of design and integration – plug and play operation.
- Wide range of sub-technologies is constantly improving and allows for broader set of applications.
- Significant ongoing research on this technology, learning curve improvements and cost reductions are expected to be significant in the future.
- Medium to low CAPEX and OPEX costs (see Table 6) for power and energy.

Cons:

- Safety concerns – overcharge and poor operation can lead to thermal runaway in cells. Additional safety and cooling measures are required.
- Critical mineral components increase exposure to supply chain risks.
- Sophisticated battery management system required.
- Need contingency planning for black start conditions.
- Recycling value chains are nascent and end-of-life waste remains a problem.
- Typically deployed with 1- 4 hours of storage – not cost-effective for long-term storage.

Vanadium flow

Vanadium flow batteries are a form of redox flow battery. Redox flow batteries use liquid electrolytes to carry and store charge. They have been relatively slower to take off than Li-ion batteries, however, appear to be increasing in popularity. The main advantage of redox batteries is that they are more suited to long-duration storage and have a longer service life than Li-Ion batteries. Power and energy are independent, and each can be scaled separately – power output is proportional to electrode surface area and energy storage capacity is proportional to the size of the electrolyte tanks. Commercialised examples include vanadium-redox flow batteries, zinc-bromine, and all-iron redox flow batteries.

Figure 17: Vanadium redox flow battery, 400 kW/1.6MWh (image courtesy of Cellcube)

Pros:

- Active materials are more easily produced compared to Li-ion batteries.
- Cycle life and calendar life are higher than Li-ion batteries with little capacity degradation over time.
- Safer and more environmentally friendly than Li-ion or Lead Acid batteries.
- More suited to longer duration discharge than Li-ion batteries, typically above four hours.
- Easily scalable, power and storage are independently scalable.
- Expected commercial improvements due to learning curve effects and large-scale manufacturing economies of scale and local production of electrolyte.
- Not as directly affected by temperature and able to operate without parasitic heating, ventilation and air conditioning (HVAC) load in many locations.
- High-value recovery rate for liquid electrolyte and battery shell, with electrolyte value linked to vanadium commodity price.

Cons:

- Less deployed and less mature than lead acid & Li-ion, although relatively mature TRL.
- Energy and power densities and efficiency lower than Li-ion although acceptable for remote power solutions.
- Electrolyte costs linked to volatile vanadium pricing.
- Medium-to-high CAPEX and OPEX costs for power and energy but expected to reduce with scale and learning curves.

Pumped hydropower

Using water pressure to drive turbine generators is a well-understood renewable energy technology. Hydropower is a heavily context-dependent option as very particular geographic characteristics are required, such as a difference in elevation and capacity for reservoirs. Pumped hydro is particularly relevant to end-of-life mines and decommissioning as it unlocks new value for assets.

Figure 18: An old gold mine will be used as a pumped hydro storage facility at the Kidston Renewable Energy Hub

Pros:

- Synchronous generation and depending on design, significant power-quality services can be provided.
- Can store significant scales of energy at a high-power output. Overall energy storage is typically large.
- Creation of value for end-of-life assets that would previously have been seen as having decommissioning liability.
- Very simple proven technologies and operationally simple.
- Significant opportunity for arbitrage, especially if grid connected.
- Life span of several decades.
- Wide-ranging temperature window.
- Capable of intra-seasonal storage and long-term storage applications.

Cons:

- Significant land-use intensity and constraints, including environmental damage and additional costs of rehabilitation if required.
- There can be dam design risks and risk of failure.
- Dependent on water supply which could be difficult to source in some conditions.
- Economically challenging without grid connection or market incentive for arbitrage.
- Very capital intensive, with high-to-medium CAPEX costs, but low-to-medium OPEX costs for power and energy.

Lead acid

As with Li-ion batteries, lead acid batteries are electrochemical cells that work based on charge transfer between electrodes. While lead is a toxic substance, the battery technology is very mature and well accepted. Similarly capable as Li-ion batteries, lead acid batteries can contribute to grid-management systems, however, their application is ultimately hindered by various chemistry limitations, such as memory of cells and poor Depth of Discharge (DoD) capabilities.

Pros:

- Relatively low initial investment.
- Well established recycling process and supply chain.
- Mature and reliable with 140 years of development.
- Robust, no complex cell management needed.
- Tolerant to overcharging.
- Low self-discharge – 5–10 per cent per month.
- Medium CAPEX and OPEX costs for power and energy.

Cons:

- Energy/power densities and efficiency lower than Li-ion.
- Significant maintenance required.
- DoD issues mean that these can typically only discharge to 50 per cent affecting life span of battery.
- Toxicity and end-of-life recovery remain a problem.

Sodium-sulphur (NaS)

A mature battery technology, sodium sulphur (NaS) batteries have been used at scale in several contexts such as standalone power systems [23]. They are expected to have a slight reduction in cost, but are limited by the required high temperature of operation (270–350°C). Generally, NaS will operate only at commercial scales but will play some role in the future where appropriate.

Pros:

- High round-trip efficiency of ~90 per cent means little energy is lost beyond self-discharge.
- High power and energy density.
- High cycle and calendar life expectancy – 4,500 cycles at 90 per cent DoD, which leads to a lifetime of about 15-20 years.
- Medium CAPEX and OPEX costs for power and energy.

Cons:

- High self-discharge (up to 30 per cent per month) limited intra-seasonal storage capabilities.
- Must be kept at high temperatures (290–390°C) and must be thermally sealed which requires additional equipment.
- Safety – contact of sodium and sulphur leads to violent exothermal reaction.

Molten salt batteries

Molten salt batteries are fundamentally different to common electrochemical cells [24]. Where electrochemical cells are based on the principle of charge transfer, molten salt batteries are based on storing energy in the form of heat in liquid salt tanks. These batteries work very well with concentrated solar thermal (CST) systems where energy is captured in the form of heat, and where process heat is a critical component. Electrical power is generated by transferring heat to a carrier such as steam and powering turbines, which can lead to significant inefficiencies compared to electrochemical cells. The application of molten salt batteries is unique but can be a useful tool in broader decarbonisation strategies.

Figure 19: Kathu Solar Park, South Africa, with molten salt storage system (image courtesy of Tractebel, Engie)

Pros:

– One of only a few technologies that can efficiently store process heat.

– Scalable technology that has high energy and power capabilities.

– Flexible energy density depending on salt chemistries used.

– Components are typically very cheap (chloride salts, etc.).

– Technology is similar to other steam turbine technologies, so understanding is advanced.

Cons:

– Significant risks of corrosion and material degradation, durability is an issue.

– Efficiency losses in electrical generation.

– Black start of molten salt storage is difficult due to freezing/solidifying of components.

– Significant temperature required (400–1000°C+).

– Commercial and technological development required.

– Plant construction is capital intensive.

– Moderate to high CAPEX costs.

Compressed air energy storage (CAES)

Compressed air energy storage (CAES) is a commercially developing technology with significant potential for intra- and inter-seasonal storage [25] [26]. Besides large-scale hydropower, CAES offers a promising bulk energy storage option. However, this capability is heavily dependent on location as it is almost exclusively available to large voids, such as salt caverns. The principle is to compress air into these voids and pressurise to a high enough pressure (50 bar+) to allow them to be de-pressured to spin turbines, generating electricity.

Transgrid recently identified Hydrostor's 200 MW/1,500 MWh compressed air storage as the preferred solution for a new backup supply in Broken Hill, NSW, after assessing multiple options. If approved the project would be delivered by 2026 [27].

Figure 20: Salt cavern compressed air (Source: Storengy)

Pros:

- Significant opportunities for long-term bulk storage.
- Technology is relatively mature and mechanically simple.
- Minimal health or safety risks.
- Moderate round-trip efficiencies of ~60 per cent.
- Several projects in operation globally.
- High capacity to store energy and power.
- Significant opportunity to repurpose end-of-life underground mines into compressed air storage voids.
- Moving from venture to mature capital investment.

Cons:

- Moderate round-trip efficiencies of ~60 per cent.
- Very capital intensive and requires significant equipment.
- Very dependent on availability of voids and underground/constructed storage capable of handling high-pressure.
- High-pressure poses equipment complexities and risks.
- Commercial development required.
- High to very-high CAPEX for power and energy.

Compressed hydrogen

Compressed hydrogen involves storing energy in synthetically created hydrogen from sources such as wind and solar, then combusting in a gas turbine or using hydrogen within a fuel cell to convert it into electrical power. The versatility of having a high-pressure gas enables many process heat or electricity generation applications. The risks associated with compressing and storing large volumes of a high-pressure explosive gas are considered within the commercial viability of hydrogen as an energy carrier compared to electricity.

Pros:

- High energy density potential (>600 Wh/L). On a mass basis hydrogen has 3 times the energy content of gasoline, however, on a volume basis this is reversed due to lower heating values.
- Ability to use hydrogen for both electricity (for stationary or mobile applications) or process heat applications through combustion.
- Storage is also compatible with geological storage such as salt caverns or underground mines.
- Potential for inter-seasonal storage as storage can be easily scaled.

Cons:

- Hydrogen storage poses some challenges and requires application of engineering solutions to storage vessels and pipe systems due to hydrogen's physical properties such as molecular size and corrosion properties, although many solutions are now becoming available.
- Inherited high cost of hydrogen supply chain, unless produced locally.
- High-pressure hydrogen needs to be adequately managed due to flammability.
- Commercial economics of hydrogen is unproven at scale, although there is widespread expectation that learning curves will improve economics, with fuel substitution in remote locations being the first economic application [28].
- Very high-to-high CAPEX and OPEX costs for energy.

Case studies

Case study A: Hybrid generation – Gold Fields

Gold Fields' Agnew mine site, 870 km north-east of Perth, is leading the way in the transition to renewable power for off-grid mining operations [29]. The Agnew Hybrid Renewable Project is Australia's largest hybrid renewable energy microgrid as well as the first mine in Australia to utilise large-scale wind generation at a mine site. The Agnew microgrid consists of 18 MW gas and 3 MW diesel generation, a 10,000-panel 4 MW solar farm, five wind turbines delivering 18 MW, a 13 MW/4 MWh battery energy storage system (BESS) and an advanced micro-grid control system. EDL owns and operates the micro-grid as part of a PPA with Gold Fields.

Since the commissioning of the microgrid, 54 per cent of Agnew's electrical power is renewable sourced power, which has resulted in a 42 per cent net emissions reduction [30], and depending on the weather conditions, up to 85 per cent of the site's electrical power may be generated by the solar farm and wind turbines [29].

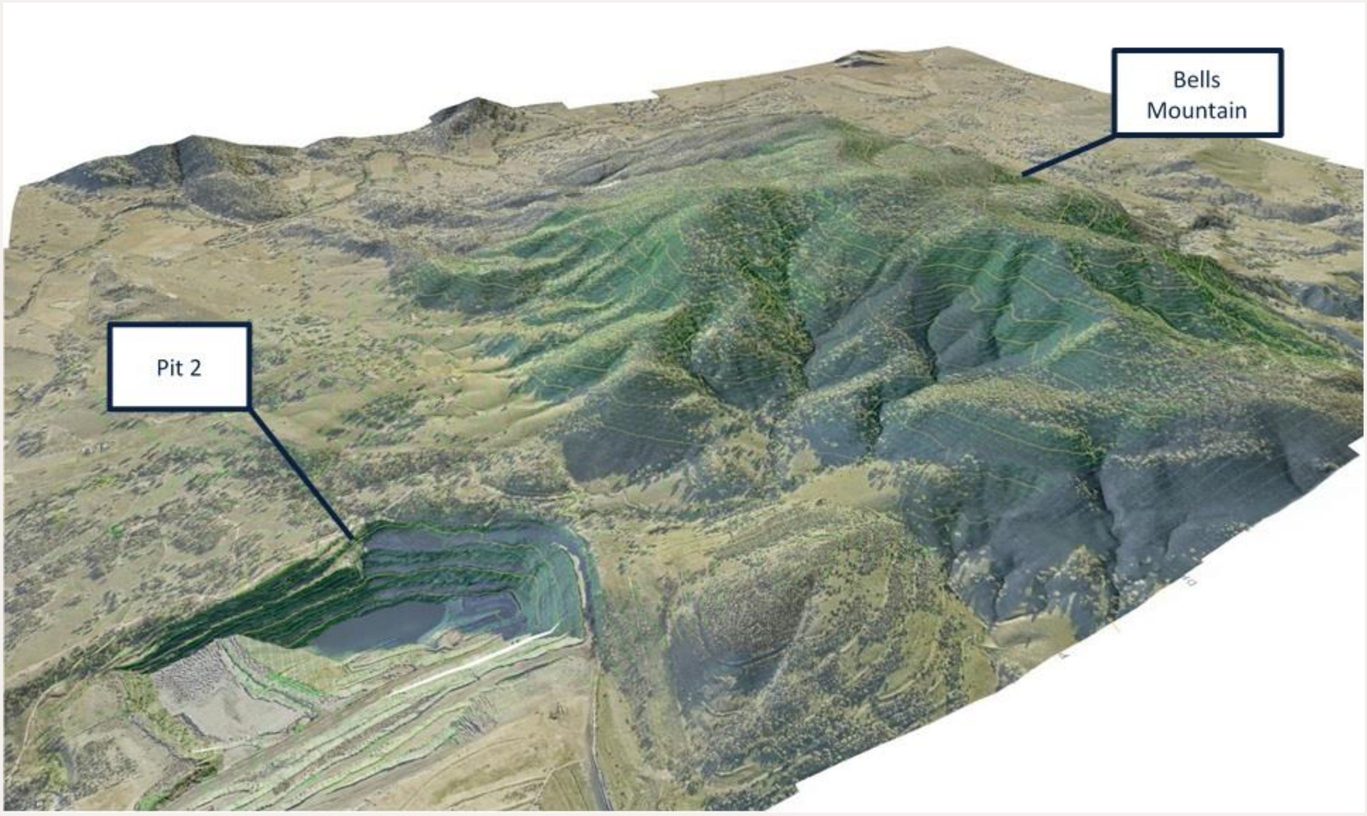
Figure 21: Wind turbines at the Agnew Renewable Energy Microgrid (image courtesy of EDL)

The total project cost was $111.6 million, with $13.5 million funded by ARENA [31]. The Agnew hybrid microgrid is forecast to reduce the mine's carbon emissions by 40,000 tCO_2-e/year [31], contributing to Gold Fields' recent commitment to reduce its Scope 1 and 2 carbon emissions by 30 per cent on a net basis and by 50 per cent on an absolute basis by 2030 [32]. The Agnew project demonstrates that technology and commercial risk can be mitigated, providing a blueprint for other companies to deploy similar off-grid energy solutions and demonstrate a pathway for commercialisation [31]. The outcome of this project also provides key learnings for Gold Fields to consider as they develop similar, and even more ambitious, strategies at other mine sites.

Case study B: Pumped Hydro – Idemitsu + AGL

Idemitsu Australia (IA) and AGL signed a memorandum of understanding (MoU) in July 2019 to assess the feasibility of developing Idemitsu's Muswellbrook coal mine in the Hunter Valley, NSW, into a 250 MW pumped hydro facility, once the mine has reached closure in 2022 [33]. A technical feasibility study has been completed and yielded positive results. AGL and IA will progress toward further project development, which includes undertaking detailed design work, engaging contractors, geotechnical drilling and securing necessary environmental approvals for the Bells Mountain pumped hydro facility [33]. The proposed hydro facility could provide eight hours of dispatchable supply, or 2,000 MWh of stored energy, by storing water in the disused mine void which could then be pumped to a second reservoir at a higher altitude, on Bells Mountain, to store potential energy. Subsequently, the water could be released under gravity and used to convert the potential energy back into electricity demand through two 125 MW fixed-speed turbines [33].

Figure 22: Proposed pumped hydro facility on Bells Mountain (image courtesy of Idemitsu)



IA and AGL are aiming to have the project commissioned and operational by 2027 [33]. This project provides an innovative rehabilitation solution to mine voids left by coal mines and other pits.

Case study C: Lithium-ion batteries – Sandfire

Sandfire was a first mover in Australia for renewable energy use in an off-grid mining application. Commissioned in June 2016, the DeGrussa solar project was the first commercial integrated off-grid solar and battery storage facility in Australia [34] and is operated by Pacific Energy. The project comprises 34,080 PV panels with a single-axis tracking system mount. The panels are connected via an extensive network of low-voltage, high-voltage, and communication cables to a 6 MW Li-ion battery storage facility and the existing 19 MW diesel-fired power station at the DeGrussa mine. Sandfire purchased power from Pacific Energy under an initial 5.5-year PPA.

Figure 23: Solar Facility at DeGrussa (image courtesy of Sandfire)

The total project cost was $39.47 million, with $20.9 million funded by ARENA [35]. The DeGrussa solar project has cut annual emissions by 15 per cent, offsetting 20 per cent of diesel consumption annually [35], a total reduction of 12,000 tCO_2-e/year [34].

Case study D: Vanadium redox flow batteries – IGO + VSUN Energy

IGO Limited (IGO) will trial a vanadium redox flow battery (VRFB) standalone power system (SPS) supplied by Australian Vanadium Limited (AVL) subsidiary VSUN Energy at its Nova Nickel Operation [36]. The SPS being installed at Nova will be based around a 300 kWh VRFB and will enable IGO to assess the performance of the SPS to power the dewatering and bore pump systems [36]. The system has been designed to provide a 100 per cent renewable energy supply for most of the year, with a diesel genset supporting periods of long cloud cover [36]. The VRFB-based SPS system trial is targeting a total renewable penetration of 85-90 per cent [36]. The target of long periods without diesel generation will not only significantly reduce the carbon emissions of these bore fields but also offer considerable reductions in operating hours for service personnel.

Figure 24: VSun Energy Vanadium Redox Flow Battery (image courtesy of VSun Energy)

VRFBs have an easily scalable energy storage capacity, high efficiency, zero emissions, very long cycle lives, and relatively low-cost of available electricity on a lifecycle basis [37]. VRFB has successfully demonstrated the ability to recycle the liquid electrolyte, with a vanadium recovery rate of 97 per cent being achieved. The battery shell can also be reused [37], making this a key difference from the disposal issues faced by Li-ion batteries. VSUN Energy is targeting high local (Australian) content for their VRFB, as they can produce the vanadium directly from local mining (through AVL) to local refining (near Geraldton, WA), to locally manufacturing the vanadium electrolyte (in Kwinana, WA) and ultimately a locally assembled SPS.

Heatmaps: Generation and storage

A range of factors must be considered in selecting the appropriate energy generation technology, with some specific considerations relevant to renewable energy technologies outlined in Table 5. Table 5

Table 5: Additional heatmap factors relevant to stationary energy generation

Factor	Description
Storage requirements	Specific to energy generation technologies, this category reflects the need for energy storage to be constructed in parallel with energy generation to be considered dispatchable, on-demand energy. In an off-grid context, VRE technologies require firming through energy storage or other dispatchable technologies to help with system strength and security.
Levelised cost of energy (LCOE)	Levelised cost of energy (LCOE) is an electricity generation technology comparison metric. It is the total unit costs a generator must recover to meet all its costs including CAPEX, OPEX and a return on investment. The LCOE is highly context dependent. For example, VRE technologies such as solar PV and wind have low operational cost and they displace sources such as CCGT and gen-sets in an energy system, and affect these technology utilisation and thus LCOE. The LCOEs provided are based on literature sources and detailed and bespoke analysis is required to calculate the LCOE for each generation technology within a system as a whole. Current LCOE is used unless otherwise stated and there may be significant changes in LCOE for some generation technologies depending on learning effects.

Table 6 highlights some of these key categories of consideration with an emission benefit relative to the base case of a diesel generator.

Table 6: Summary table for relevant power generation technologies

Technology description	Emission benefit	Technology Readiness	Commercial Readiness	Storage requirements	REC Generation	Land intensity	CAPEX intensity	OPEX intensity	Indicative LCOE	ESG Concerns	Safety & health benefit	Decarb Score
Liquid fuel Gen-sets (Diesel)	0.00 to 0.00 tCO_2e/kL	TRL 9	CRI 6	Fuel as storage	No	Low	Low	High	269 – 384 AUD/MWh[15]	Yes	No benefit	0
Liquid fuel Gen-sets (Ammonia)	2.71 to 2.71 tCO_2e/kL	TRL 9	CRI 1	Fuel as storage	Potentially	Low	Low	High	~ 228 AUD/MWh in 2040[16]	Yes	Safety & Health risk	5
Biomass Generation	2.71 to 2.71 tCO_2e/kL	TRL 9	CRI 2	Fuel as storage	Potentially	Low	Medium	High	111 – 162 AUD/MWh[17]	Potentially	No benefit	6
Closed-Cycle Gas Generation (CCGT) (Gas)	1.29 to 1.38 tCO_2e/kL	TRL 9	CRI 6	Fuel as storage	No	Low	Medium	Medium	67 – 213 AUD/MWh[18]	Yes	No benefit	4
Closed-Cycle Gas Generation (CCGT) (Green Hydrogen)	2.71 to 2.71 tCO_2e/kL	TRL 9	CRI 1	Fuel as storage	Potentially with hydrogen	Low	Medium	High	~ 269 AUD/MWh in 2040[19]	Potentially	Safety & Health benefit	5
Geothermal	2.71 to 2.71 tCO_2e/kL	TRL 9	CRI 1	Fuel as storage	Yes	Moderate	Very high	Medium	247 – 698 AUD/MWh[20]	Yes	No benefit	5
Solar photovoltaic (PV)	2.71 to 2.71 tCO_2e/kL	TRL 9	CRI 6	Short- and long-term requirements	Yes	High	Medium	Low	44 – 65 AUD/MWh[21]	No	Safety & Health benefit	8
Wind turbines	2.71 to 2.71 tCO_2e/kL	TRL 9	CRI 6	Short- and long-term requirements	Yes	Very high	Medium	Low	49 – 61 AUD/MWh[22]	No	Safety & Health benefit	8
Concentrated solar thermal (CST)	2.71 to 2.71 tCO_2e/kL	TRL 9	CRI 3	Fuel as storage	Yes	Moderate	High	High	158[23] – 190 AUD/MWh[24]	No	Safety & Health benefit	6

Note: Emission benefit is compared to a diesel gen-set. Commercial readiness, storage requirements and other metrics are also within a specific context of off-grid power generation. Storage is discussed in more detail later in the paper and this table is intended to provide a summary of the general character of different technologies. Note also that LCOE is indicative only and needs to be evaluated within a site-specific context [38] [39] [40].

15 Taken from Lazard's LCOE Analysis v11, page 2. Converted to AUD at 0.73 USD/AUD.

16 No gen-set data could be found. In its place is a CCGT representation of Ammonia power generation. Taken from Cesaro et al. and converted at 0.73 USD/AUD. No data for years around 2020, so forward-looking 2040 LCOE taken. Note that this LCOE is refers to 2040.

17 CSIRO, Gen Cost 2022. Taken from Table B.9, Ranges from low to high for 'Biomass small scale' in 2021. It is likely that conversion to liquid fuels would cost more as this 'Biomass direct' factor represents solid fuels. This LCOE does not represent a liquid fuel biodiesel substitute for diesel, but a 'biomass generation' in a general sense.

18 CSIRO, Gen Cost 2022. Taken from Table B.9, high for open-cycle and reciprocating engines in 2021 for peaking loads. Where low is taken as no carbon price in 2021 for flexible load.

19 Taken from Cesaro et al. and converted at 0.73 USD/AUD. No data for years around 2020, so forward-looking 2040 LCOE taken. Note that this LCOE is refers to 2040.

20 ENGIE Impact internal analysis. Based off two phase geothermal pilot and commercial geothermal power plant.

21 CSIRO, Gen Cost 2022. Taken from Table B.9, Ranges from low to high for solar photovoltaic in 2021.

22 CSIRO, Gen Cost 2022. Taken from Table B.9, Ranges from low to high for onshore wind in 2021.

23 Fichtner, High Level Cost Estimate for CST Reference Plants in Remote WA, 2022.

24 CSIRO, Gen Cost 2022. Taken from Table B.9, high for solar thermal 12hrs in 2021. This LCOE includes energy storage.

As with energy generation, context is critical for selecting the appropriate energy storage technology and a range of additional considerations apply.

Table 7: Additional heatmap factors relevant to energy storage

Factor	Description
Short-term services	The ability to supply on-demand grid-management services for various energy storage technology. Short-term services represent the power quality focused usage of energy storage on a timescale of seconds and minutes. This is further discussed in in this section under '*Energy storage specific considerations*'.
Long-term services	The ability to supply intra- and inter-seasonal services for various energy-storage technologies on a timescale of days and months. This is focused much more on aggregate energy volumes, rather than power output.
Temperature window	A specific concern for energy storage technologies, there are often temperature windows for optimal operation. This is an important consideration for mines that are frequently exposed to high temperatures (e.g. Marble Bar), or low temperatures (e.g. Alaska).
Energy density	The energy density of an energy storage technology roughly represents the energy stored per unit volume. Because of the heterogeneous nature of the energy storage technologies (gravitational vs. electrochemical, for example) this is a general comparison.
Power density	The power density of an energy storage technology roughly represents the power outputs per unit volume. Because of the heterogeneous nature of the energy-storage technologies (gravitational vs. electrochemical, for example) this is a general comparison.
Battery life	This represents the average useful life of a battery technology under standard operating conditions. Energy storage technologies do not maintain the exact same performance over time. Diminishing performance is expected, but each energy storage technology will degrade at different rates. The longevity of energy storage technologies is influenced by how the battery is operated, including the frequency of charging and discharging. There can be end-of-life uses, extending battery life for decades. For example, Li-ion batteries may no longer be suitable for BEVs due to diminishing power and energy density after 5-10 years. These batteries may be re-purposed for power quality or long-term energy storage.

Table 8 considers the range of energy storage technologies across relevant storage factors, explained later in this section under '*Energy storage specific* considerations'. Contextual factors that will affect technology selection include the location and the type of energy to be stored and the composition of stationary energy generation.

Table 8: A summary table for a wide range of relevant energy storage technologies

Technology description	Type	Technology Readiness	Commercial Readiness	Short-term services	Long-term services	Land intensity	CAPEX intensity	OPEX intensity	Learning curve	Power component cost	Energy component cost	ESG Concerns	Ease of implement-ation	Temperature window	Energy density	Power density	Battery life	Safety	Decarb Score	Grid support	Arbitrage	Inter-seasonal
Lithium ion (Li-ion)	Electro-chemical	TRL 9	CRI 6	Advanced management ability	Day to day arbitrage	Low	Medium	Low	Significant reduction in cost expected	CAPEX: 299 – 384 AUD/kW OPEX: 3.0 – 3.8 AUD/kW[25]	CAPEX: 228 – 355 AUD/kWh OPEX: 4.6 – 7.1 AUD/kWh[26]	Yes	Very easy	High & Low temperature issues	High	Very high	5–15 years	Safety & Health risk	9	8	4	3
Vanadium flow (Redox flow)	Electro-chemical	TRL 8	CRI 4	Advanced management ability	Day to day arbitrage	Moderate	Very high	Medium	Significant reduction in cost expected	CAPEX: 487 – 634 AUD/kW OPEX:15.9 – 20.7 AUD/kW[27]	CAPEX: 292 – 365 AUD/kWh OPEX: 7.4 – 9.3 AUD/kWh[28]	Yes	Easy	High & Low temperature issues	Low	Low	15–25 years	No benefit	7	6	4	2
Pumped hydropower	Mechanical	TRL 9	CRI 6	Advanced management ability	Intra-seasonal storage	Very high	Very high	Medium	No reduction in cost expected	CAPEX: 719 – 5,304 AUD/kW OPEX: 16.8 – 286 AUD/kW[29]	CAPEX: 7 – 137 AUD/kWh OPEX: 0 – 0.1 AUD/kWh[30]	Yes	Very difficult	No impact of temperature	Very low	Low	>50 years	Safety & Health risk	6	8	8	6
Lead Acid	Electro-chemical	TRL 9	CRI 5	Advanced management ability	Day to day arbitrage	Low	High	Low	No reduction in cost expected	CAPEX: 375 – 665 AUD/kW OPEX:~9 AUD/kW[31]	CAPEX: 358 – 609 AUD/kWh OPEX: ~9 AUD/kWh[32]	Yes	Easy	High & Low temperature issues	Low	Moderate	<5 years	No benefit	6	7	4	2
Sodium-Sulphur (NaS)	Electro-chemical	TRL 9	CRI 6	Advanced management ability	Day to day arbitrage	Low	High	Low	Little reduction in cost expected	CAPEX: 290 – 494 AUD/kW OPEX: 8.7 – 14.8 AUD/kW[33]	CAPEX: 540 – 920 AUD/kWh OPEX: 10.8 – 18.4 AUD/kWh[34]	Yes	Moderate	Non-ambient operation	High	Moderate	15–25 years	Safety & Health risk	7	7	5	3
Flywheel	Mechanical	TRL 8	CRI 5	Advanced management ability	No long-term storage	Low	Very high	Medium	No reduction in cost expected	CAPEX: 470 – 1,646 AUD/kW OPEX: 196.3 – 1,203 AUD/kW[35]	CAPEX: 2,351 – 9,404 AUD/kWh OPEX: 0.5 – 3.3 AUD/kWh[36]	No	Easy	Maximum temperature issues	Low	Very high	5–15 years	Safety & Health risk	6	8	4	1
Molten salt batteries	Thermal	TRL 8	CRI 3	Some management ability	Intra-seasonal storage	Moderate	High	Medium	Moderate reduction in cost expected	No data.	CAPEX: 34 – 516 AUD/kWh OPEX: No Data[37]	No	Moderate	Non-ambient operation	Moderate	Low	15–25 years	Safety & Health risk	6	4	5	6
Compressed Air Energy Storage (CAES)	Mechanical	TRL 8	CRI 2	Some management ability	Inter-seasonal storage	Low	Very high	High	Little reduction in cost expected	CAPEX: 598 – 1,572 AUD/kW OPEX: 67 – 343 AUD/kW[38]	CAPEX: 3 – 141 AUD/kWh OPEX: 0.2 – 1.1 AUD/kWh[39]	No	Difficult	No impact of temperature	Very low	High	25–50 years	No benefit	5	7	7	7
Compressed hydrogen	Chemical	TRL 6	CRI 2	Some management ability	Inter-seasonal storage	Low	Very high	Low	Significant reduction in cost expected	CAPEX: 1,670 – 2,063 AUD/kW OPEX: 50 – 62 AUD/kW[40]	CAPEX: 11 – 30 AUD/kW OPEX: Negligible AUD/kW[41]	No	Difficult	No impact of temperature	Very high	High	25–50 years	Safety & Health risk	6	7	8	9

Note: This is interpreted in the context of off-grid electricity storage and generation with the best-case design taken. Decarb score incorporates all weighted scores, while the scoring categories of grid-support, arbitrage, and inter-seasonal are based purely on function and ignore non-functional risk categories. Where appropriate, contextual scaling of function is undertaken to represent a like-for-like technology comparison. Note that the power and energy component costs are indicative only and need to be evaluated in a site-specific context.

25 ENGIE Impact internal estimates. Based off RMI, US DoE, and other estimates.
26 ENGIE Impact internal estimates. Based off RMI, US DoE, and other estimates.
27 ENGIE Impact internal estimates. Based off RMI, US DoE, and other estimates.
28 ENGIE Impact internal estimates. Based off RMI, US DoE, and other estimates.
29 ENGIE Impact internal references. Taken from a range of AEMO submissions and parliamentary studies. Geographically limited and highly context dependent.
30 ENGIE Impact internal references. Taken from a range of AEMO submissions and parliamentary studies. Geographically limited and highly context dependent.
31 ENGIE Internal estimates combined with "An evaluation of energy storage cost and performance characteristics, Energies (2020), 13, 3307 (Pacific Northwest, Argonne, and Oak Ridge National Laboratories)"
32 ENGIE Internal estimates combined with "An evaluation of energy storage cost and performance characteristics, Energies (2020), 13, 3307 (Pacific Northwest, Argonne, and Oak Ridge National Laboratories)"
33 ENGIE Impact internal estimates. Based off IRENA and internal estimations.
34 ENGIE Impact internal estimates. Based off IRENA and internal estimations.
35 ENGIE Impact internal estimates. Based off IRENA and internal estimations.
36 ENGIE Impact internal estimates. Based off IRENA and internal estimations.
37 ENGIE Impact internal estimates. Based off IRENA and internal estimations. Data independent of Concentrated Solar Thermal is difficult to find, so capital costs are not presented.
38 ENGIE Impact internal estimates. Based off IRENA and internal estimations.
39 ENGIE Impact internal estimates. Based off IRENA and internal estimations.
40 ENGIE Impact internal estimates. Summation of liquefaction, storage, and regasification costs. Assumes that compressed hydrogen is stored through liquid hydrogen. There are a range of inter-seasonal hydrogen forms, such as liquid organic hydrogen carrier (LOHC) that are not considered.
41 ENGIE Impact internal estimates. Summation of liquefaction, storage, and regasification costs. Assumes that compressed hydrogen is stored through liquid hydrogen. There are a range of inter-seasonal hydrogen forms, such as liquid organic hydrogen carrier (LOHC) that are not considered.

Technology considerations

Emissions benefit

Key technologies are likely to include a combination of solar and wind coupled with appropriate energy storage, all of which produce zero emissions on an operating basis. Moving away from liquid fuel gen-sets and CCGT technologies will enable deeper decarbonisation and assist with reducing operational costs. Gen-sets and CCGT technologies may assist in the transition, providing reliability, but will inherit the emissions of the fuel type used (most commonly diesel and natural gas).

Energy storage technologies are often neutral in terms of a quantifiable emissions benefit as they are not sources of generation, though they do facilitate greater use of zero emissions generation.

Technological readiness

All plausible and scalable energy generation technologies are identified at Technology Readiness Level (TRL) 9. The technological maturity of energy storage varies by purpose and technology type, with electrochemical and mechanical batteries rated TRL 8 or TRL 9. Compressed hydrogen technologies (and other chemical batteries) are less mature.

Batteries used for short-term services, such as grid-management and arbitrage tend to be mature, while long-duration batteries used for intra- or inter-seasonal storage may be technically well developed, there remain few examples at scale. Exceptions to this include a few examples of CAES or larger scale pumped hydro, which are more location context driven.

Many of these generation and storage technologies will complement each other and not compete for energy supply and support. In many cases, the technical feasibility of a reliable system implies the coordination of several types of technology to ensure power quality.

Commercial readiness

Decarbonised energy generation is commercially advanced and continues to improve due to economies of scale in production. Wind and solar (specifically PV) have become the lowest cost form of generation in many mining contexts, achieving a Commercial Readiness Index (CRI) level of 6 in recent years. CCGT and ICEs are also commercially advanced but only when utilising traditional fuels such as diesel and natural gas, which limit their ability to participate in decarbonisation.

Short-term energy storage for the purposes of intermittency and integration of moderate levels of VRE has rapidly improved in commercial viability. Strong learning curve effects for both wind and solar in combination with equally rapid advances in the reduction of battery costs have led to a step-change in commercial viability, achieving CRI 6. Many electrochemical cells work more effectively than traditional grid management techniques, even being able to provide advanced grid management services such as synthetic inertia and frequency control.

Long-term energy storage is comparably more complex. The significant volumes of energy required to be stored under intra- and inter-seasonal applications lend itself to more limited applications such as large-scale pumped hydro or CAES.

While VRE technologies such as wind and solar offer low-cost generation options, firming a high penetration of VRE remains a challenge. The greater the penetration of VRE, the higher the cost of firming, due to the increased costs associated with maintaining power quality (see Figure 25). In an off-grid setting, as VRE penetration increases to high levels, short-term requirements associated with grid stability increase steeply. Likewise, the risk associated with longer periods of time of poor solar or wind resources implies reliance on fossil fuel generation or the need for costly intra-seasonal or inter-seasonal energy storage.

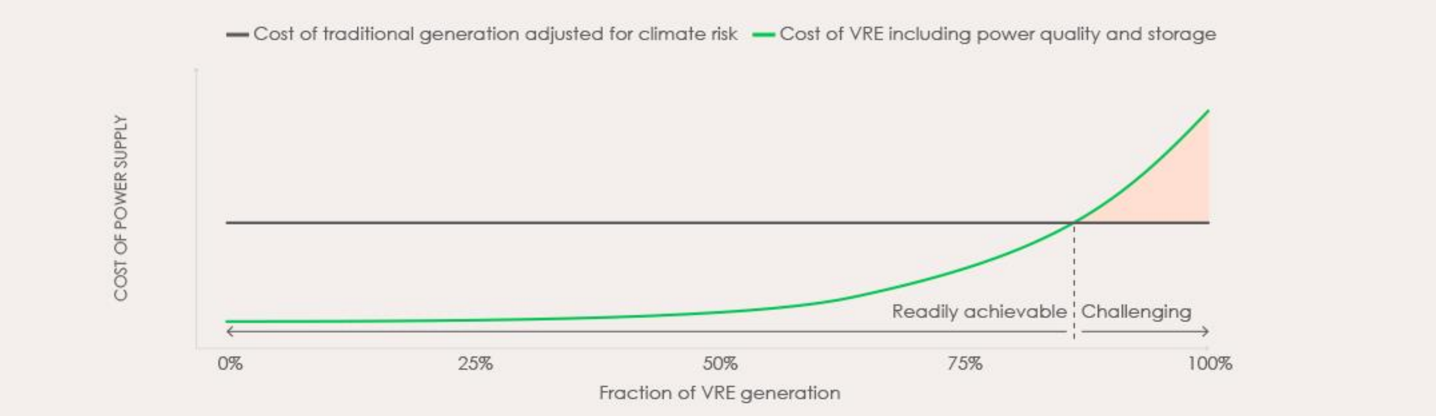


Figure 25: Example of the cost of VRE integration as a fraction of VRE penetration for an off-grid context

Integration and prohibitive power quality issues do not arise until significant VRE penetration is achieved, typically more than 80 per cent VRE generation. Therefore, such an issue is generally only apparent during the last few steps of generation decarbonisation, and significant abatement can be achieved up to this point.

Land intensity

Renewable energy technologies are typically more land-intensive (W/m2) than traditional generation technologies. Analysis by Zalk & Behrens [41] detailed a range of land intensities for various fuels, and some of the relevant fuels can be seen in Figure 26. Both major renewable energy technologies – wind and solar PV – are much less energy dense than natural gas generation, so for the same capacity in MW, more land area will be required. However, with renewable energy technologies land can be concurrently used for other purposes such as pasture.

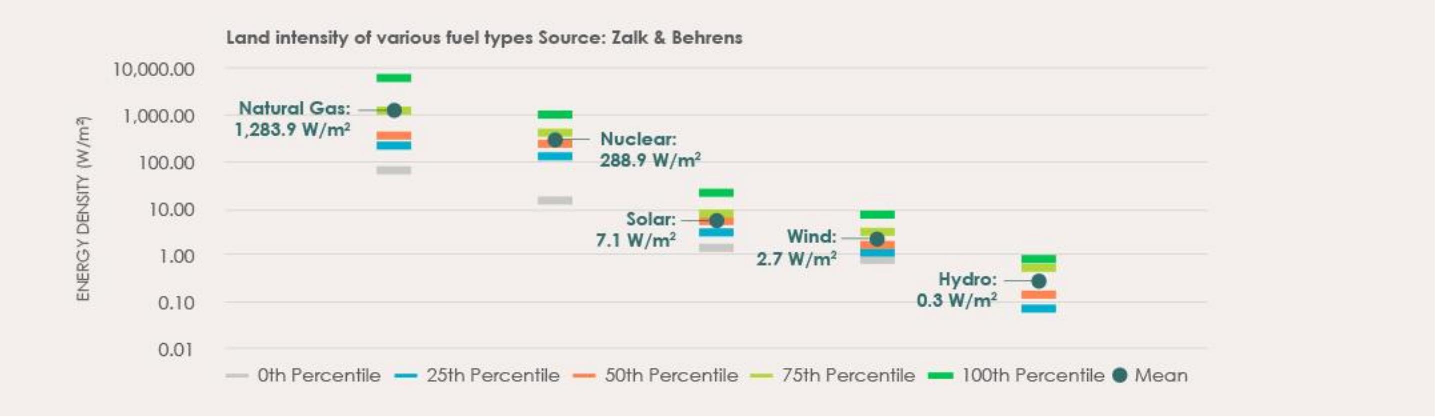


Figure 26: The land intensity of various energy generation technologies. Lower energy density implies more land area required for the same capacity

Land considerations are highly context dependent. While pumped hydro uses significant areas of land, it may be viable under certain geographies or conditions. CAES requires a significant amount of underground storage volume, such as salt-caverns or other natural phenomena.

For most applications, the land use of energy storage is generally a negligible consideration compared to the area required for various generation technologies.

Ease of implementation

Site specifics, in particular the ease of transport access and whether there is grid connection, will be the key determinant of the ease of implementation. The modular properties of smaller technologies such as solar PV and gen-sets can assist with ease of implementation, as opposed to technologies with larger mechanical systems such as wind and solar CST. In off-grid settings, most VRE technologies are best installed with short-term storage to increase power quality, as in Case Study A. Short-term energy storage from electrochemical cells is easily installed as such technologies are often plug-and-play and modular in design.

There is little or no expectation of impacts on production beyond standard maintenance scheduling, as switching between traditional generation and many renewable technologies is not mutually exclusive with ongoing power generation. As energy storage requirements become larger and more complicated, there may be a need to consider process or operational changes as a trade-off to the cost limitations of storage, which implies the need for load management and demand response to prevent excess generation and storage capacity build-out, and to optimise economic outcomes.

While pumped hydro and other land and capital-intensive technologies will require significant civil works and infrastructure to integrate, where achievable, these technologies can provide significant power quality services required through the later stages of deep decarbonisation.

Health & safety benefit

The impacts of decarbonisation technology on health and safety are generally positive.

Where the health and safety impact may vary is when zero carbon liquid or gas fuels are used. An example is the toxicity of ammonia as discussed above. With such fuels, operators will need to consider management of any new risks carefully.

Energy storage introduces a different set of safety risks for consideration. Some electrochemical batteries can experience thermal runaway and require additional safety measures. Likewise, mechanical storage technologies such as pumped hydro or CAES require civil inspection and maintenance to ensure that any risk of catastrophic failure is avoided.

CAPEX & OPEX intensity

The capital intensity of both zero-carbon energy generation and energy storage is significant, but rapidly decreasing. The operational cost of these technologies tends to be negligible to balance their capital intensity. The capital cost of energy storage is expected to decrease for most storage technologies, although material capital costs appear to be unavoidable for long-term storage.

The major difference between traditional technologies such as CCGT and diesel gen-sets, and renewable technologies such as wind and solar, is that operational expenditure (OPEX) is substituted for capital expenditure (CAPEX). For mid or junior miners who operate with a high OPEX to CAPEX ratio, this may pose a significant challenge to financial strategies, but present significant competitive opportunities in terms of reduced cash costs of production through low unit cost renewable energy.

Energy storage specific considerations

Short-term services

Providing short-term services supports grid control and maintenance, and while technically complex, most energy storage technologies can supply advanced grid management services. Electrochemical batteries are increasingly playing grid-support roles both on and off grid, such as the Hornsdale battery [42] in the South Australian grid and the BESS in Gold Fields Agnew mine (Case Study A).

Long-term services

In contrast to short-term services, long-term services are less about providing immediate grid support and more about providing security of supply when VRE resources diminish. Long-term services focus on aggregate volumes of energy.

Outside of large-scale hydro storage, there are very few zero-carbon technologies that can currently supply long-term storage services. The notable, but commercially immature, technologies of compressed hydrogen, CST or CAES are the exceptions.

Learning curve

The price of energy storage technologies will decrease if economies of scale take hold. Forecasting lower costs for commercially maturing technologies such as Li-ion is commonplace [43]. Using historic examples to drive assumptions, and projections, the same could be said for technologies such as vanadium flow, or other technologies, as highlighted by IRENA [44].

ESG concerns

Climate action is a part of a broader trend towards integrating sustainability at a more general level. As scrutiny over materials and supply increases, so should the attention to how and where raw materials are sourced. As discussed in *Mining in a Low-emissions economy: The Compelling Case for Decarbonisation*, this is a significant opportunity for Australian mining companies.

There is a significant body of work around the required production, recycling, and end-of-life activities for electrochemical batteries such as Li-ion [45]. Second-use applications (such as using electrochemical batteries from EVs for grid support) are expected to be commonplace, helping minimise the ESG impact of battery production. As focus shifts toward recycling, attention will also increase on sustainably sourced raw materials as recycling is forecast to only ever fulfil a minority of demand [46].

Material movement (Underground and surface)

Summary

Movement of mined material is currently dominated by diesel-fueled ICEs, commonly drawing 30–50 per cent of a mine's total energy requirements across the various commodity groups [19].

Decarbonising material movement is critical. Technological, financial, and commercial innovation is occurring rapidly in this space, with complementary technologies such as automation providing opportunities for a range of co-benefits. Mine planning, electrification and new approaches to material movement will be fundamental tools in the push for mining decarbonisation. If integrated at the start of mine life, capital-intensive technologies such as trolley assist (TA) and In-Pit Crushing and Conveying (IPCC) can be attractive choices, whereas fuel switching or indirect electrification may be more appropriate for operations with shorter mine lives and brownfields sites.

Although many of these innovations are underway, there remain barriers to adoption. While there is an obvious preference for mature technologies, mining companies are seeking to trial and adopt innovative solutions, seizing the opportunity and putting low-emissions material movement technology to the test.

As it is heavily context dependent, optimal solutions for material movement will vary for greenfield and brownfield projects, as well as underground and open-pit operations.

Figure 27: Summary of decarbonisation scores for key haulage technologies

Figure 28: Summary of decarbonisation scores for key rail technologies

Technology insights

- **Trolley assist:** Advanced solutions exist to support haulage electrification at appropriate mine ramps, particularly in new build scenarios.
- **Battery electric vehicles:** Proven benefits in small to mid-sized vehicles, personnel carriers and underground applications, with range and battery technologies evolving for larger vehicles.
- **Green hydrogen/fuel cell electric vehicles:** Gaining increasing focus and investment to achieve commercial readiness, especially for larger and long-haul vehicles.

Practical considerations

- **Decarbonise electricity and electrify first:** Electrification using renewable energy will cut emissions and operating costs and unlock co-benefits in complementary technologies such as transport and automation.
- **Invest in solutions for material movement:** As the scale of material movement emissions is significant, decarbonisation provides a significant opportunity to become best-in-class, broadening investor appeal.
- **Coordinate infrastructure investment:** Combine new electrification infrastructure investments with other relevant decarbonisation initiatives to maximise value, whether in designing new operations or retrofitting existing approaches.
- **Underground operations offer earlier opportunities:** Development of electrified underground technologies is more mature and offers more timely decarbonisation benefits while open pit solutions gain momentum. Displacing diesel underground has immediate health benefits and can reduce ventilation needs and associated OPEX costs [47].
- **Plan to save emissions and cost:** Mine planning is an important risk mitigation measure, to ensure mine design is compatible with low-emissions technologies, avoiding sunk costs and maximising life-of-mine returns.

Technology in brief: Haulage and conveyors

There are many methods of material movement, each with application to specific contexts. Typically, the usage of haulage and conveyors moves most material within a mining operation.

A non-exhaustive summary and introduction of various material movement technology solutions is provided below, identifying illustrative examples of both underground and open pit solutions.

Internal combustion engine (ICE)

Most material movement is currently powered by ICEs. Original Equipment Manufacturers (OEMs) such as Caterpillar, Komatsu, and Liebherr are well-established in this supply chain. Within the decarbonisation context, the objective is to move away from the ICE and towards alternative engines. The fuel used determines the emissions from an ICE, and ICEs ultimately inherit the risks associated with the fuel, such as carbon, logistics costs and pricing volatility.

Figure 29: Diesel haul truck with an Internal Combustion Engine (ICE)

Alternative fuels

In principle, many fuels can be used in an ICE and there is the potential for environmentally sustainable fuels to be considered.

Pros:

– ICEs are the default existing technology for many material movement applications.
– Using ICEs with zero carbon liquid fuels can provide an early stepping-stone to complete decarbonisation.
– Combustion of liquid fuels may continue to be required in long-distance material movement until newer technologies are proven in this application.
– Transitioning emission-intensive engines to zero or low-emission engines is possible.
– Low-CAPEX technology relative to zero carbon haulage technologies.

Cons:

– Emission benefit is heavily dependent on the liquid fuel used and substitutes may carry environmental or economic considerations.
– Combustion is an inherently inefficient process.
– NOx emission from vehicle engines is a well-known issue and has been a subject of mitigating technology development for many years.

Trolley assist (TA)

Trolley assist systems provide a solution to reduce GHG emissions by electrifying truck haulage, reducing diesel consumption and increasing efficiency. A TA system consists of a pantograph, electronic control system and overhead electric lines to which vehicles can connect during operation. The truck is equipped with a pantograph that makes the connection between the vehicle and the overhead power distribution line. An on-board electronic control system regulates the power coming from the overhead cables and integrates that with the electrical drive system of the truck.

Figure 30: Trolley assist vehicle (Image courtesy of BluVein)

Pros:

- Potential increase in maximum power that can be delivered to the truck by up to 50 per cent relative to ICE.
- Improves energy efficiency of the complete system due to the direct connection.
- Allows significant reductions in diesel engine emissions at the mine by allowing substitution of diesel energy with electricity during the most demanding part of the truck work cycle.
- In the underground environment, the latest designs provide an improved safety environment, as all conductors are housed within ingress protection (IP) rated slots.
- Productivity gains as fewer trucks required due to higher average speed.

Cons:

- Involves heavy infrastructure and high capital expenses, and potential impacts on flexibility should be considered early.
- Implementing a TA system in a mine has an impact on the footprint of the roads. Additional ramp space is required to be allocated for the foundations of the support pillars.
- The mine ramp characteristics: (length, elevation, slope, corners, width, etc.) may influence the feasibility of this technology.
- These design features must typically be considered at mine planning stage to make TA viable and economic.

In-pit crushing and conveying (IPCC)

IPCC systems offer the opportunity for mining operations to become less energy intensive and therefore less carbon intensive, with lower operation and maintenance costs. In IPCC systems, the primary crushing takes place in the pit with the crushed material conveyed to the following process phases. Illustrative costs indicate that while the initial CAPEX for a typical IPCC may be as much as 60 per cent higher than the conventional approach, the IPCC's OPEX was 43 per cent lower, resulting in a 28 per cent reduction of the life-of-mine net present cost (NPC).

Pros:

- Improved operational resilience.
- Elimination of the need for large fleet of haul trucks.
- Reduce the associated cost of road and truck maintenance.
- Can be considered a zero-carbon solution if the energy is supplied from renewable sources.
- Well-established technology with long history of usage.

Cons:

- They can only be used in pits that have ramp slopes less than 10°, with some high-angle systems allowing for slopes of up to 20°.
- Longer mine life required (5-10 years) to make it economically feasible as there are significant infrastructure costs.
- Heavily context dependent, predominately favoured towards deep pit operations due to relative cost increases in haulage.

Battery electric vehicle (BEV)

Battery-powered mining vehicles have been deployed for almost 30 years, but in recent years large-scale adoption of the technology is being considered, driven by various factors, including health and safety, heat, GHG emissions and energy efficiency. BEVs are becoming more common in underground material movement applications. However, energy storage, range and charging limitations exist for open-pit operations with various new pilots underway to test application in heavy haulage.

Figure 31: 3ME mine vehicle (image courtesy of 3ME Tech)

Pros:

- Enables decarbonisation due to substitution of diesel energy consumption with electrical energy consumption.
- Elimination of diesel and other exhaust gas components in the underground environment.
- Less heat, vibration and noise associated with replacement of diesel motors with electrical motors.
- Batteries in vehicles can act in a grid supporting role through charging and discharging.
- Significant economies of scale and modularity of equipment.
- Lower maintenance costs and higher efficiency.
- Flexible operation comparable to ICE.
- Ability to use regenerative braking while descending to recoup energy.

Cons:

- Significant charging infrastructure required and therefore requires some additional initial capital investment.
- Charge time may be significant (hours) compared to alternatives.
- Range is currently limited subject to battery capacity, with significant variation across battery chemistries.

Fuel-cell electric vehicle (FCEV)

FCEVs provide a technical alternative to BEVs where higher range and payload time are required. FCEVs use hydrogen gas to power an electric motor. Since they are powered by electricity, fuel-cell vehicles are considered EVs, however, their range and refuelling processes are comparable to conventional trucks.

Pros:

- The major benefit of FCEVs is that they generate no direct carbon emissions from their use.
- As fuel cell trucks may be rapidly refuelled, FCEVs have high up-time.
- FCEVs can potentially have a higher power-to-weight ratio than BEVs and can theoretically haul more per trip.
- Hydrogen has a higher relative energy density compared to electrical storage.
- Flexible operation comparable to ICE as it is mobile and can operate in many contexts.

Cons:

- The range of an FCEV truck is typically lower than a comparable diesel ICE-equipped truck.
- Similarities to the risks inherent with diesel ICEs, but with a different fuel:
  - Centralised risks on hydrogen as a fuel source.
  - Inherits environmental, economic, and social risks of hydrogen as a fuel source.
  - Inherits technical and safety issues from hydrogen.
- If not green hydrogen, potential for embodied emissions within hydrogen production.

Plug-in hybrid electric vehicle (PHEV)

PHEVs provide a viable solution to decarbonise transportation. However, the benefits of hybrid vehicles are often limited due to weight penalties while only providing a partial decarbonisation solution. Hybrid diesel/battery electric are common in mine vehicles in the form of trolley hybrids, offering a reduction in fuel consumption and the ability to recover lost energy.

Pros:

- Partial elimination of diesel and other exhaust gas components.
- Improves primary energy efficiency through energy recovery techniques.
- Combining established technologies that leverage existing servicing industries.
- Delivers a higher torque solution as the electric drive can support the ICE.

Cons:

- Subject to correct duty cycle design, hybrid vehicles may be less flexible in terms of mobility compared to ICEs.
- Not a fully decarbonised technology - residual particulate and GHG emissions remain.

Case studies

Case study E: H2 Electrolyser Production and FCEV – Anglo American + ENGIE

At Anglo American's Mogalakwena mine in South Africa, a 3.5 MW electrolyser is being built to produce hydrogen on site for use in fuelling a prototype 290T 2MW hydrogen-powered, fuel-cell electric hybrid haul truck, which was unveiled in May 2022. As part of its FutureSmart Mining™ innovation program, Anglo American is working with ENGIE to develop a hydrogen-powered FCEV. Anglo American had analysed its mine site power requirements for both mobile and fixed needs. This focused on allowing it to come up with a mix of renewable energy systems that would allow it to be carbon neutral [48].

The pilot truck at Mogalakwena is a converted 29t Komatsu 930E which has been developed over a three-year program. It uses eight Ballard FCveloCity-HD 100 kW modules [48] to provide a peak power of more than 2 MW. Anglo American expects to roll out this technology across the Mogalakwena fleet and those at their other operations in years to come [49].

Figure 32: Large mining truck (image courtesy of Anglo American)

A contract for a 3.5 MW electrolyser from ENGIE has been signed, with the electrolyser capable of producing 1,000 kg of hydrogen per day [48].

Case study F: Electric mining trucks – Caterpillar + BHP

BHP and Caterpillar announced in August 2021 that they had entered an agreement to develop and deploy zero-emissions battery-powered large mining trucks at BHP sites to reduce their operational GHG emissions [50].

These new trucks will be designed and built by Caterpillar and will facilitate the path of zero-emissions mining worldwide. This milestone is the result of 12 months of close collaboration between BHP and Caterpillar in analysing the energy demands and the options to apply this new technology on BHP sites [51]. BHP will provide input to the development and testing processes of these trucks.

This initiative will support BHP's long-term goal of achieving net zero operational GHG emissions by 2050 [51].

Case study G: Autonomous haul trucks – Caterpillar + Rio Tinto

In September 2021, Rio Tinto and Caterpillar signed an MoU for Caterpillar's development of zero-emissions autonomous haul trucks, to be trialled at Gudai-Darri, one of Rio Tinto's WA mining operations [52].

This collaboration will see Rio Tinto work collaboratively with Caterpillar to advance the development of Caterpillar's 220t 793 zero-emissions autonomous haul trucks, 35 of which are to be deployed on site. This will also include validating Caterpillar's emerging zero-emissions technology [52].

Rio Tinto has also agreed to deploy three Caterpillar fully autonomous water trucks at Gudai-Darri [53]. These initiatives will support Rio Tinto's ambition to reach net zero emissions across their operations.

Case study H: Charging trolley assist – BluVein

BluVein is a joint venture between Olitek (Australia), which for more than 25 years has been active in the mining technology and innovation space, and Evias (Sweden), which over the past 10 years has been developing and refining its Electric Road System and charging-on-the-go technology [54].

BluVein's extension into the mining industry allows grid power to be supplied directly to haul vehicle's traction motors and charging systems. This feature eliminates all battery swapping and static vehicle charging requirements, enables smaller and lower-cost batteries and increased haulage speeds. BluVein is agnostic to vehicle manufacturer which allows a mixed fleet of mining vehicles to use a safe IP-rated power rail [55]. It is currently working on two products, the first suited to 60t payload haul vehicles in underground mines, selective open pits and quarries, and the second suited to large open-pit haul trucks of 220t payloads. BluVein is working closely with OEMs Volvo, Epiroc, Sandvik and MacLeans Engineering.

According to BluVein, its game-changing system effectively eliminates all exposed high-voltage conductors, providing significantly improved safety, compliance with mining's electrical regulations and reduced capital cost compared to the alternatives [54].

Figure 33: BluVein trolly assist (image courtesy of BluVein)

Most importantly, the technology enables the removal of diesel emissions from underground operations, as well as eliminating vehicle GHG emissions in all applications. As of August 2021, BluVein has received financial backing to accelerate to commercialisation from eight major mining companies – BHP, Vale, Glencore, Newcrest, OZ Minerals, Northern Star, Agnico Eagle and AngloGold Ashanti [54].

Case study I: Hydrogen-powered trucks – FMG

Fortescue Future Industries (FFI) has completed the design and construction of the world's first hydrogen-powered demonstrator haul truck, with systems testing now underway in Perth, WA [56]. This is a fuel-cell electric vehicle (FCEV) utilising both hydrogen fuel cells and batteries.

FFI's Green Team are trialling technology on hydrogen, ammonia and battery power for locomotives, ship engines, haul trucks and drill rigs for technology demonstration purposes. Prototype machines will be developed and deployed to Fortescue Metals Group (Fortescue/FMG) sites.

Haul trucks at Fortescue mine sites account for 26 per cent of their Scope 1 operational emissions in 2021 [57], therefore decarbonising haul trucks either by hydrogen or electric fleets will have a substantial impact on Fortescue's carbon footprint across their operations. The hydrogen FCEV in these prototypes will produce no harmful fumes, and the only exhaust produced will be water.

Figure 34: FMG hydrogen haul truck trial (image courtesy of FFI)

Case study J: Battery electric locomotive – Roy Hill

In September 2021, Roy Hill announced the purchase of the world's first fully battery-powered, heavy-haul locomotive from Wabtec, which will transform the cost of transporting iron ore from pit to port [58]. The FLXdrive battery-electric locomotive has an energy capacity of 7 MWh and will arrive in Australia in 2023 [59]. It can pull loaded wagons with 35,000 tonnes of iron ore, while at the same time reducing the entire train's fuel consumption [60]. The FLXdrive will replace one of the diesel-electric locomotives to form a hybrid and will recharge during the trip through regenerative breaking [59].

The locomotive has a Trip Optimiser System, an intelligent cruise-control system programmed using artificial intelligence to manage the overall train energy flow and distribution. This allows the train to respond in the most energy-efficient way to every curve and grade of the track [59]. Wabtec are also developing the next generation of zero-emission locomotives using hydrogen internal combustion engines, batteries, and hydrogen fuel cells [59].

Heatmap: haulage and conveyors

Table 9 provides a high-level comparative summary of relevant haulage technologies. It focuses on the replacement of diesel in haulage, as conveyors can be considered for an end-state of decarbonisation as material movement is electrified.

Table 9: A summary table for relevant diesel ICE substituting technologies, with ICE included as a reference

Technology description	Emission Benefit	Technology Readiness	Commercial Readiness	Ease of implementation	CAPEX Intensity	OPEX Intensity	Safety & Health Benefit	Decarb Score
Internal combustion engine (ICE)	0.00 to 0.00 tCO_2e/kL	TRL 9	CRI 6	Easy	Low	Medium	No benefit	**0**
Trolley assist (TA) – without green power	0.82 to 0.41 tCO_2e/kL	TRL 9	CRI 6	Difficult	High	Low	Safety & Health benefit	1
Trolley assist (TA) – with green power	2.71 to 2.71 tCO_2e/kL	TRL 9	CRI 6	Difficult	High	Low	Safety & Health benefit	**8**
Fuel-Cell Electric Vehicle (FCEV) – without green power	-4.58 to -1.85 tCO_2e/kL	TRL 6	CRI 1	Moderate	High	High	Safety & Health benefit	**-3**
Fuel-Cell Electric Vehicle (FCEV) – with green power	2.71 to 2.71 tCO_2e/kL	TRL 6	CRI 1	Moderate	High	High	Safety & Health benefit	**5**
Plug-in Hybrid Electric Vehicle (PHEV)	0.13 to 0.22 tCO_2e/kL	TRL 8	CRI 4	Moderate	Medium	Medium	Safety & Health benefit	1
Battery Electric Vehicle (BEV) – without green power	0.63 to 0.28 tCO_2e/kL	TRL 6	CRI 2	Moderate	High	Low	Safety & Health benefit	1
Battery Electric Vehicle (BEV) – with green power	2.71 to 2.71 tCO_2e/kL	TRL 6	CRI 2	Moderate	High	Low	Safety & Health benefit	**7**
In-Pit Crushing and Conveying (IPCC) – without green power	0.66 to 0.48 tCO_2e/kL	TRL 9	CRI 6	Difficult	Very high	Low	Safety & Health benefit	1
In-Pit Crushing and Conveying (IPCC) – with green power	2.71 to 2.71 tCO_2e/kL	TRL 9	CRI 6	Difficult	Very high	Low	Safety & Health benefit	**7**

Note: All factors are FY21 NGER; SWIS grid-factor with no LGC (green power) procurement assumed. This analysis is general and applies to 'haulage', encapsulating the general trends among open-pit and underground together. Simplifications are made for PHEV, there is also replacement diesel consumption as it is a hybrid.

Technology considerations

Emissions benefit

The key aspect informing total emissions benefit is the source of fuel. If the above examples of electrification were coupled with energy derived from onsite renewables or green-power procurement, the emission benefit for each electrifying technology would be up to 2.71 tCO_2-e/kL compared to diesel. This includes both direct and indirect electrification of fuels (BEV, IPCC, TA, and FCEV where fuel is produced using clean energy) and highlights the importance of co-procurement of green power with additional electricity demand.

Without REC or LGC procurement (green power), on-site generated hydrogen powered by (fossil fuel intensive) grid electricity for FCEV use can lead to an increase in emissions, as the emissions associated with the replacement electricity required for electrolysis may be greater than the abated diesel, per kilolitre (kL). The 'green power' FCEV case implies that hydrogen is produced from renewable energy. The maximum theoretical abatement per kL of diesel abated is 2.71 tCO_2e/kL as that implies all diesel abatement and no replacement emissions.

Technology readiness

Compared to the current dominant technology for haulage, the ICE, and the conveyor material movement mechanism within IPCC, all other technologies are less mature with lower technology readiness levels [61].

For haulage, the specific context is important as this sets the mining operating requirements for vehicle weight, payload, and charging opportunities. While light BEVs are now highly developed, large-scale BEV pilots are still being developed to the standard ready for an open-pit operation. The same can be said for FCEV.

In contrast, for underground mining, BEVs are relatively well-developed as they have been in operation for some time. This is largely due to the limitation of size for haulage vehicles and previous initiatives to limit diesel particulate matter (DPM) in underground operations.

Mine configuration and whether the operation is a greenfield or brownfield project will influence potential solutions. This is best explained through the example of TA systems. TA involves the construction of ancillary infrastructure parallel to haulage paths, such as electrical powerlines or rails. Two considerations that dictate the viability of this infrastructure are whether there is the space and distance required. With greenfield operations, mine specifications and planning can be conducted to allow for the required space, which will be costly to retrofit in existing pits or underground mines. The cost of TA would roughly be proportional to the distance required, which can also be mitigated based on innovative greenfield mine planning being used to minimise haulage path length.

While ICEs may be regarded as having high TRLs, this is a simplification, and the type and chemical composition of the fuel used in an ICE plays a significant role in the technological readiness of the engine. For example, there are early designs for Compressed Natural Gas (CNG) and Liquified Natural Gas (LNG) engines, but these are nascent, especially for heavy mobile assets such as haul trucks. While there will be technical modifications required, using an ICE with a zero-carbon fuel (such as ammonia) will largely have the same result as a BEV from an emissions point of view, but with a significantly more mature technology ecosystem.

Commercial readiness

Most technologies assessed function at the required scale but may struggle to meet commercial requirements imposed by operating conditions. While there are some examples of zero carbon haulage technologies, the overall commercial readiness (CRI) is still generally low (with certain exceptions mentioned above) [3]. This will change, but the challenge is avoiding being locked-in to a specific technology.

As seen in Table 9, technologies with a higher TRL generally have a higher CRI. TA, ICE, and IPCC technologies have been used at scale within current mining operations. FCEV and BEV are still in technological development for haulage and the CRI is lower.

Research and development opportunities

- TA and IPCC are both technologically mature in most contexts. However, TA has a range of sub-technologies (such as) where further R&D is required to move these technologies from the lab to a full-scale mining operation.
- Specific challenges to embedding BEV into effective operations, such as recharging, are already being addressed through R&D efforts [62]. However, pilot projects will help to pinpoint and direct focus on these barriers.
- For many haulage contexts, such as medium-to-long distances, current zero carbon technologies are insufficient due to distance and energy storage constraints. Significant R&D in both BEV and FCEV technology is required to scale these technologies in mining operations.
- Significant R&D opportunities exist in haulage, specifically for FCEV and BEV technologies as their primary limitation is technological. Underground mining has a proven history of BEV which will help transition this technology to open-pit mine requirements.
- Managing TA system planning with operational use is key to making TA commercially viable at scale. The R&D is not necessarily technological, but innovation in mine planning can allow for commercial deployment of TA.
- IPCC is a mature technology with little R&D required. Like TA, the commercial viability of IPCC will be determined by the early stages of mine planning.

Ease of implementation

Like-for-like substitution is the lowest risk and easiest form of implementation. Substituting one fuel in an ICE with a zero-carbon fuel has the lowest burden of implementation. Each step away from this provides potential challenges in implementation. However, these changes may also generate efficiencies.

A key consideration from an implementation perspective is how it affects production in the implementation phase. Retrofitting to allow for zero carbon fuel consumption could be done through maintenance phases and stepped through an existing fleet, having minimal additional impact on production.

Moving from a truck-based material movement strategy to a conveyor-based material movement strategy such as IPCC would likely represent the largest implementation barrier, as this would not only affect mobile and stationary assets, but also have significant implications on mine planning. This again highlights the difference between greenfield and brownfield projects. Implementation of new technology sometimes requires more than additional infrastructure, with the significant planning prior to implementation potentially limiting the capacity of brownfield projects to deploy some technologies.

For technologies such as TA and IPCC there is a lack of flexibility. Both civil works and prior mine planning are required to utilise the infrastructure-intensive TA and IPCC technologies. The suitability for TA and IPCC will be dependent on mine layout.

Financial overview: CAPEX & OPEX intensity

An important consideration for junior to mid-tier mining companies is the relative capital intensity of projects. While a lower cost of capital may be available for zero carbon initiatives, the initial cost for many decarbonisation initiatives remains high, and haulage is no exception.

Compared to a baseline capital expenditure for traditional diesel ICEs, all other technologies appear likely to have a higher associated CAPEX in the short term, although many technologies that use fuels produced from renewable electricity (green hydrogen, green ammonia, etc.) will reduce in OPEX as the marginal cost of electricity from VRE trends to zero.

The mine life and whether the operation is a greenfield or brownfield project have a major influence on CAPEX and OPEX intensity. For example, for greenfield TA systems, the mine ramp can be designed to allow for the required space, which would be costly to retrofit later in mine life. As the cost of TA is proportional to the ramp distance, innovative greenfield mine planning can also be used to minimise haulage path length and therefore cost.

Health and safety benefit

Haulage is a high-risk environment, and the physical safety of workers is of the highest importance in any mining operation. Great improvements to personal safety are expected to come with the implementation of complementary technologies such as autonomous haul trucks.

The removal of diesel ICEs will also remove a source of DPM and improve the air quality locally. This effect may be minimal in an open-pit context, but underground this is a significant issue and co-benefit opportunity for decarbonised operations.

Abating diesel removes a source of combustion, and therefore reduces the fire risk on site. However, depending on the replacement technology and operation context, electricity can provide a source of ignition which will require electrical suppressants (such as SF_6, a significant GHG) around high-voltage equipment. Noting additional issues with battery combustion, additional safety mechanisms will need to be built into battery components on site.

Heatmap: transport and distribution

Over longer distances, material movement focuses less on conveyor and haulage and more on rail, shipping, and road-trains. Importantly, depending on contractual arrangements and definitions of operational control [63], the emissions associated with transport and distribution may shift from Scope 1 to Scope 3.

While Scope 3 emissions are not currently within emissions reporting boundaries, and many junior to mid-tier mining operations will not directly operate long-distance material movement solutions, mining companies are increasingly being required to address Scope 3 emissions sources. As such, a summary of some technologies related to rail decarbonisation can be seen in Table 10.

Even if emissions are not under the operational control of the mine operator, there is still exposure to carbon risk for Scope 3 emissions. Depending on the emissions target set, it may still be required to contribute to the elimination of these emissions. Using Table 10, the same issues of capital intensity and long distance apply to the electrification of rail.

Joint-ventures and co-ownership models will require a complex and case-by-case approach where emissions are apportioned. Depending on the target methodology used, where there is a Scope 3 emissions reduction target, some non-operational-control emission reduction strategies will have to be employed.

Shipping and long-haul road trains have not been included in this analysis but will also require alternative technology solutions to address decarbonisation.

Table 10: A summary table for relevant rail substituting technologies, with rail ICE included as a reference and the base case for emission benefit (shown in kL). All emission factors are FY21 NGER; with SWIS grid-factor with no LGC (green-power) procurement assumed.

Technology description	Emission Benefit	Technology Readiness	Commercial Readiness	Ease of Implementation	CAPEX Intensity	OPEX Intensity	Safety & Health Benefit	Decarb Score
Internal combustion engine (ICE)	0.00 to 0.00 tCO_2e/kL	TRL 9	CRI 6	Very easy	Low	Medium	No benefit	0
Fuel-Cell Electric Vehicle (FCEV) – with greenpower	2.71 to 2.71 tCO_2e/kL	TRL 6	CRI 1	Easy	High	High	Safety & Health benefit	5
Fuel-Cell Electric Vehicle (FCEV) – without greenpower	-6.57 to -1.85 tCO_2e/kL	TRL 6	CRI 1	Easy	High	High	Safety & Health benefit	-3
Battery Electric Vehicle (BEV) – with greenpower	2.71 to 2.71 tCO_2e/kL	TRL 8	CRI 2	Moderate	High	Low	Safety & Health benefit	7
Battery Electric Vehicle (BEV) – without greenpower	0.06 to 0.28 tCO_2e/kL	TRL 8	CRI 2	Moderate	High	Low	Safety & Health benefit	1
Green Ammonia Rail	2.71 to 2.71 tCO_2e/kL	TRL 4	CRI 1	Easy	Low	High	Safety & Health risk	6
Overhead electrification – with greenpower	2.71 to 2.71 tCO_2e/kL	TRL 9	CRI 6	Moderate	High	Low	Safety & Health benefit	8
Overhead electrification – without greenpower	0.31 to 0.41 tCO_2e/kL	TRL 9	CRI 6	Moderate	High	Low	Safety & Health benefit	1

Technology considerations: In brief

Most of the technology considerations for haulage apply to rail technologies, therefore the details have been condensed to avoid duplication of the explanations above. Overhead powerlines and electrification is comparable to TA, but technologically proven at scale as significant parts of rail networks are already electrified. Decarbonising rail will come down to distance and availability of capital. Most rail technologies except for FCEV and Ammonia ICE have been commercially tested or proven at scale. Companies such as BHP, Rio Tinto, and Roy Hill are planning to progress with BEV rail [64] [65] [66], which removes the need for expensive overhead electrical infrastructure.

While parallel electrical infrastructure may be economically plausible over short distances, as distance increases, the economics may become more challenging. Analysis must always be conducted on a case-by-case basis, which is especially true for capital-intensive activities such as rail.

In-mine operations

Summary

Within a mining operation (whether open-pit or underground), stationary equipment is used to extract ore through various activities such as excavation, drilling and shovelling. There are overlaps with material movement, however, in this context, in-mine operations are used to describe equipment that is not required to move over a great distance, based around activities such as excavation and liberation from a rock-face.

Both material movement and in-mine operations can be decarbonised using similar technology types but face a different set of challenges. The maturity and development of heavy-diesel replacing technologies such as BEV, hybrid, and TA technologies will largely mirror the technological maturity of material movement technologies. In essence, both in-mine equipment and haulage involve decarbonising diesel as an energy source.

In general, in-mine activities require limited or short-range mobility as compared to material movement, and as a result can be easier to electrify due to reduced need for inbuilt energy storage.

Activity overview

Activity	Drilling	Blasting	Excavation	Loading	Dewatering	Ventilation
Original energy	Physical	Chemical	Chemical	Chemical	Electrical	Electrical
Electrification potential	Moderate	Low	High	Moderate	High	High
Decarbonisation potential	High	Scope 3 Source	High	Moderate	High	High

Figure 35: Summary of electrification and decarbonisation potential across high level in-mine operations

Technology insights

- **Drilling:** Electric drill options are readily available. A range of technologies exist and currently drills can either be electric, diesel-electric, or diesel-powered.
- **Blasting:** While decarbonising ammonium nitrate emulsion is challenging, embedded emissions can be decarbonised by suppliers using green hydrogen in ammonia production.
- **Excavation:** Electrification options are available for major equipment such as backhoe excavators. Design for electrified equipment at the mine planning phase.
- **Loading:** Fully electric front-end loaders are available for underground mining. Decarbonised open pit solutions are in development with progress being made on mobility challenges.
- **Ventilation:** Use electric solutions for heavy-duty ventilation fans and further reduce underground ventilation requirements by electrifying mobile equipment to remove heat loads.
- **Dewatering:** Available electrification options exist for direct substitution in dewatering technologies, with demand expected to increase due to diminishing ore grade and deeper mines.

Practical considerations

- **Decarbonise electricity needs:** Significant decarbonisation can be achieved in in-mine operations, particularly underground, as significant amounts of equipment are already powered by electricity.
- **Invest in stationary energy:** Stationary equipment may be easier to decarbonise using electrification, renewable energy and energy storage compared with the diverse requirements of mobile equipment.
- **Manage ventilation requirements:** Electrification can reduce ventilation needs due to lower levels of heat generation and particulate emissions.
- **Address Scope 3 emissions:** For example, in explosives and reagents, especially where reductions in Scope 1 and 2 emissions are more difficult to achieve across the mining operation.

Technology in brief: In-mine operations

A range of solutions will be required to decarbonise in-mine operations, focusing on technologies that can electrify work and heat. The scale, type of ore, geography, mine layout, and other items will impact the feasibility of decarbonisation of in-mine operations. Most activities require equipment that has limited mobility requirements, reducing the need for energy storage in the equipment.

Activity introduction

Core activities within an in-mine operation relevant to the decarbonisation of both underground and open pit mines are outlined in Figure 36. Each group contains further sub-sets of activities and available methods or technologies, however, decarbonisation methods will apply similarly.

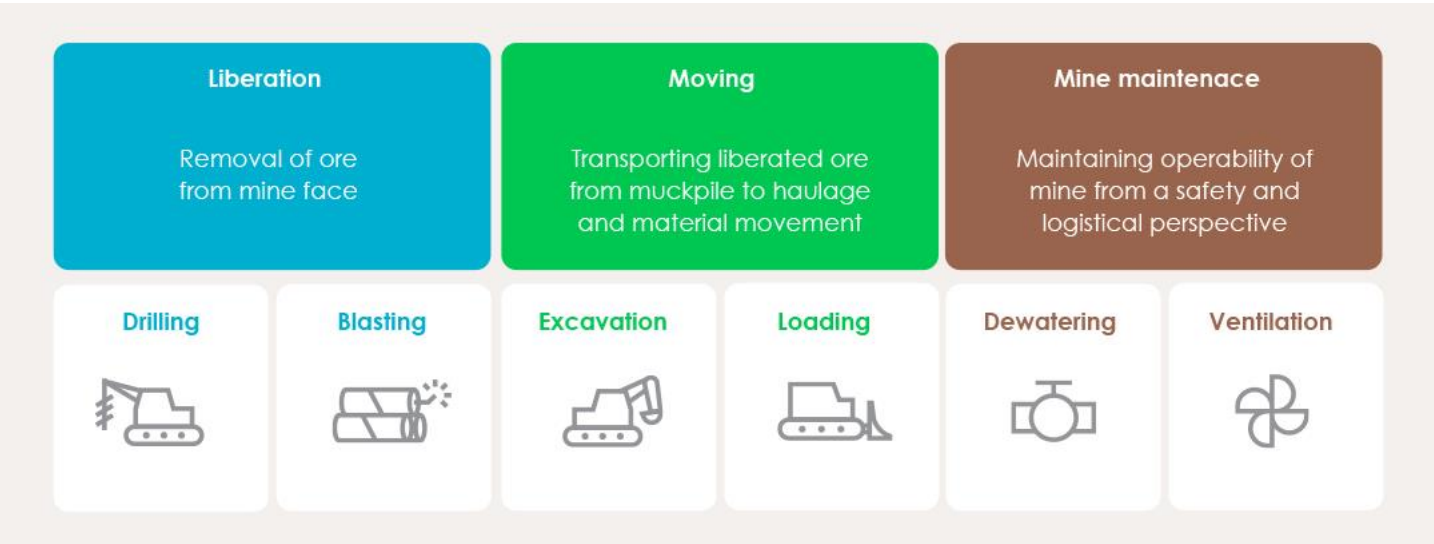


Figure 36: Summary of main activities and equipment for in-mine operations. Note that ventilation is only relevant for underground mining [67]

Electrification strategy

While the major technology solutions are similar to material movement – predominately ICEs – the context in which these engines are employed differs. Whereas in material movement, the work generated is required to transport the material over longer distances, usually on an incline, in-mine operations focus on the liberation and in-mine movement of ore. The location is relatively fixed, and the distances are short.

As a result of the short distances and fixed location, in-mine operations can effectively be considered stationary engines that apply work. **The primary constraints of battery life and power-to-weight ratio that currently limit the rate of electric technology uptake in material movement are not necessarily limiting factors for in-mine operations.**

Beyond blasting, the expectation is that in-mine operations can be electrified in the future by the adoption of technology solutions that replace the chemical energy input (diesel) with renewable energy. The requirement for **additional electrical infrastructure would only be a relatively small increase to the scale of electrical infrastructure as compared to the requirements from the electrification of material movement**, and likewise the impact on total or peak energy demand would be expected to be small compared to the scale of haulage demand.

Generally, **if the equipment is powered by a diesel generator, it can be easily electrified** as the technology is already electric, with the aim to replace the diesel generator with a connection to an operation's electricity network. The challenge will be in constructing the electrical infrastructure in an efficient no-regrets manner.

An additional advantage of electrification is the reduction in not only GHG emissions but also particulate matter and harmful air pollutants. For mine operators, particularly underground, this will bring a significant health and safety benefit compared with the business-as-usual diesel solution.

Activity assessment: In-mine operations

The potential for electrification against the current status of each activity is summarised in Table 11.

Table 11: Summary of decarbonisation of in-mine operations. The scope for electrification is either direct or indirect electrification, which largely represents the degree to which the in-mine activity can be decarbonised. Mobility requirements are a crude representation of how mobile, and thus how much energy storage is required, for each activity.

Activity description	Current Electrification	Direct Electrification Potential	Indirect Electrification Potential	Mobility Requirements
Excavation	Low	Very high	High	Irregular
Loading	Low	High	Moderate	Regular
Ventilation	High	Very high	Moderate	Stationary
Drilling	Low	High	Moderate	Regular
Shoveling	Low	High	Moderate	Regular
Dewatering	High	Very high	Low	Stationary
Blasting	Very low	Very low	High	Stationary

Drilling

Preparation for explosive charges used in blasting requires drilling holes into the ground at various depths so charges can be efficiently detonated. Drilling in open-pit mining is a minor consumer of energy and many forms of drilling equipment use electricity to power compressors that pneumatically power the drills. Underground mining uses a wider range of liberation techniques such as long-wall mining, sub-level caving, and block caving. All three involve drilling, but only long-wall mining solely uses mechanical energy, while both caving techniques involve explosives. In most contexts, drilling is largely a preparatory activity and requires relatively little energy.

Drills are generally either appended to light or medium vehicles for geophysical logging, or significant pieces of equipment, in the instances of rotary blasthole rigs. With each scale of drill, the direct work is supplied through hydraulic (water) or pneumatic (compressed air) pistons and motors. In turn, these fluids are actuated by diesel-powered engines that generally supply electricity. As the power is largely sourced from electricity, the preceding diesel consumed can be substituted and associated emissions abated.

Electric drill rigs are readily available and in use [68]. A summary of the electrification and decarbonisation of drilling can be seen in Figure 37.

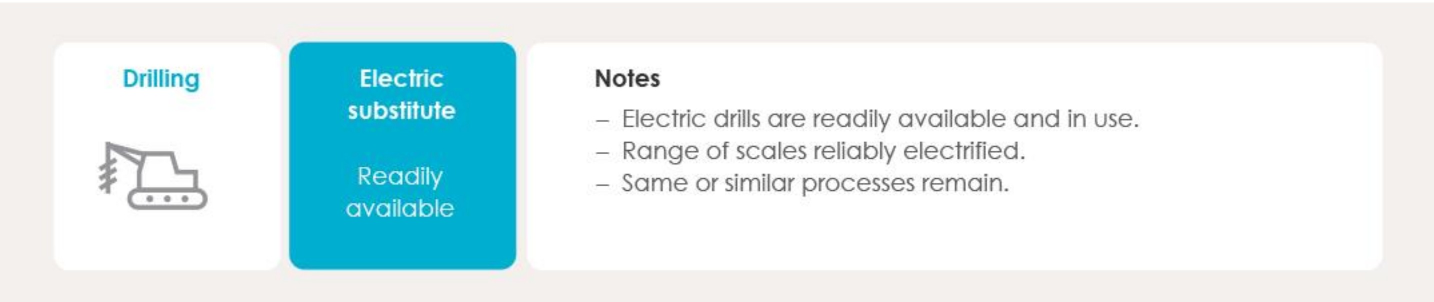


Figure 37: Drilling decarbonisation summary

Blasting

Blasting is much more complicated to decarbonise as it involves a chemical explosion, rather than controlled combustion. Fortunately, the direct (Scope 1) emissions associated with blasting are often negligible compared to other emissions sources such as haulage.

There are high embodied emissions (Scope 3) in the chemicals used, mainly associated with upstream ammonia production. As with the mechanisms described in Figure 51, the embodied emissions are associated with the energy within the chemical bonds of the explosive.

The main sources of direct emissions associated with ammonium nitrate fuel oil (ANFO) and ammonium nitrate emulsion (ANE) come from the fuel oil in explosion. ANFO and ANE are strong oxidising agents, with the diesel fuel reductant releasing CO_2.

For each tonne of ANFO used there is approximately 0.2 tCO_2-e associated with the direct emissions (Scope 1) and approximately 1.6 tCO_2-e associated with indirect (Scope 3) emissions [69]. A summary can be found in Figure 38, highlighting the difficulty to decarbonise direct emissions.

The key learning is that the direct emissions from blast charges will be very difficult to decarbonise, but they will be negligible compared to broader mining operations. Due to the comparative size of emissions, a larger impact would be achieved through focusing on the upstream chemical processing (embodied emissions in ammonia), rather than the blast process itself.

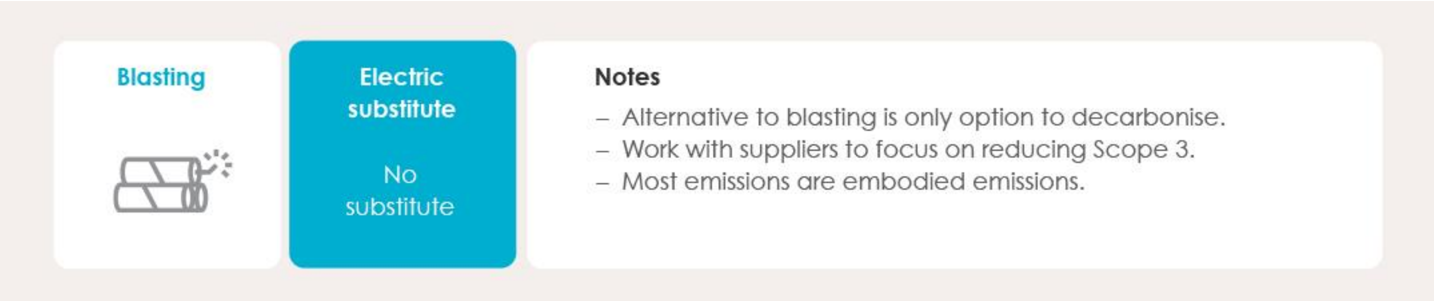


Figure 38: Summary for decarbonising blast charges

Excavation

Moving liberated ore to the run-of-mine (ROM) stockpile starts with excavation. Excavation encompasses several substitutable technologies that are dependent on contextual factors such as geography, scale, and mine layout. With heavy lifting requirements and diminished mobility, excavators can have significant power ratings.

The largest digging (backhoe) excavators can have a power rating greater than 3 MW, while the largest bucket-wheel excavators (Bagger 293 or Bagger 288) have power ratings greater than 16 MW. These giant excavators are powered by direct transmission electricity. These significant machines are stationary enough to be supplied by external electricity suggesting an electrification strategy for excavation can lend itself to decarbonisation through renewable energy supply (refer to the section on Stationary energy).

A similar approach using externally supplied decarbonised electricity can also be used to decarbonise smaller equipment. Smaller-scale electric excavators from Liebherr [70] and Caterpillar [71] are already used in the mining context.

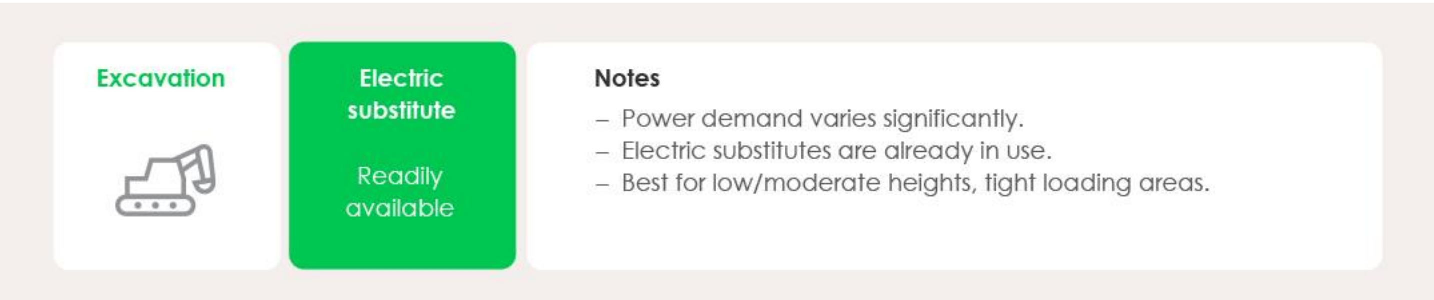


Figure 39: Excavation summary of electrification and decarbonisation

Loading

An alternative to backhoe excavation is often using front-end loaders to transport ore from ore pile to haulage. Generally smaller than excavators, front-end loaders are much more versatile and mobile equipment. The largest front-end loaders can consume up to 1.5–1.7 MW of power and can be used in various mining applications [72].

The ability to decarbonise loaders is currently a function of scale. Electrification of underground loaders is a proven and well-understood technology, with underground electric loaders commercially available in different variations. The driver for this was the various health and safety co-benefits due to reduced ventilation requirements and diminished DPM. While smaller in scale, the use of electric loaders underground demonstrates that loading can be electrified, an example being 3ME Tech's battery technology for underground heavy vehicles [73].

As open-pit loaders tend to be larger and more mobile, energy storage currently constrains their ability to be electrified. With battery constraints and mobility requirements limiting electrification, the ability to directly substitute existing technology for electric loaders is currently limited in this context due to the need for energy storage to support vehicle power and range. Case study K provides an example of how 3ME Tech are working to overcome these constraints for small to mid-size front-end loaders.

Loading	Electric substitute Depends on scale	**Notes** – Underground electrification immediately available. – Open-pit electrification progressing. – Complementary to excavation techniques.

Figure 40: Loading summary of electrification and decarbonisation

Full electrification is an end-state strategy, particularly in the open pit context, and intermediary steps to decarbonise loaders will be necessary to achieve mid-term annual decarbonisation targets and minimise lag in achieving cumulative targets. Using Table 4 in the *Fuels: energy carriers* section as a reference, consider if there may be immediate and short-term fuel substitutes. Alternatively, as backhoe excavators are electrifiable, a transition in mine planning and operation to alternative forms of in-mine movement can help to achieve both interim and long-term targets.

Ventilation

Significant ventilation can be required for underground mining operations. The two main requirements for ventilation are the removal of gases and particulate matter from explosions or combustion, and the removal of fugitive emissions in the context of coal mining. In addition to the significant mass of gas required to be moved, some mines require cooling or heating of air. The cost of ventilation has been a driver in the early electrification of many underground mining operations.

Most ventilation equipment is already electrified, which can be decarbonised by sourcing the stationary power generation from renewable energy sources (see Figure 41).

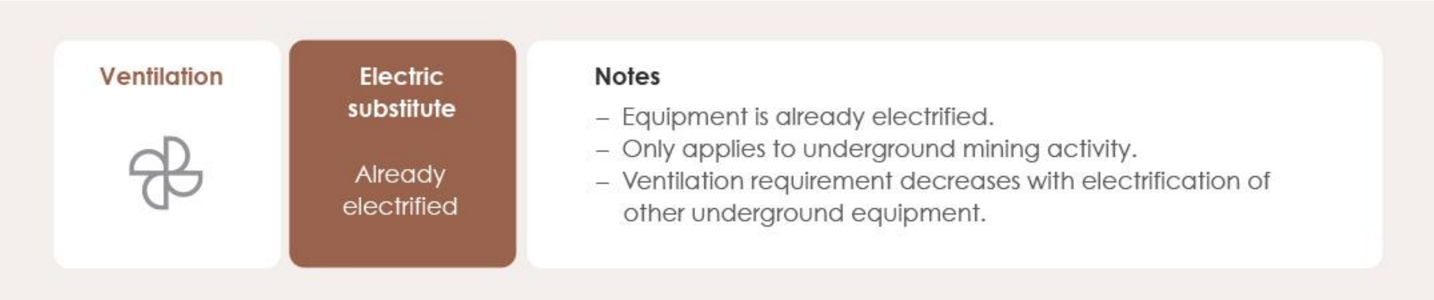


Figure 41: Summary of ventilation decarbonisation and electrification

Dewatering

The removal of water is critical for underground mining and important for many open-pit mining operations. Underground mining operations typically go through the water table, so constant dewatering is often required. In a similar trend to Figure 53, as mines run deeper because ore grade decreases, so too does the dewatering requirement.

Electric pumps are the standard technology for dewatering in underground mining but some in open-pit contexts may be powered by diesel generators. The energy demand can be significant, so maintaining or switching to electrified pumps and decarbonising that electricity, through microgrid supply or integration into the broader electricity network, is how growing dewatering demands can be decarbonised.

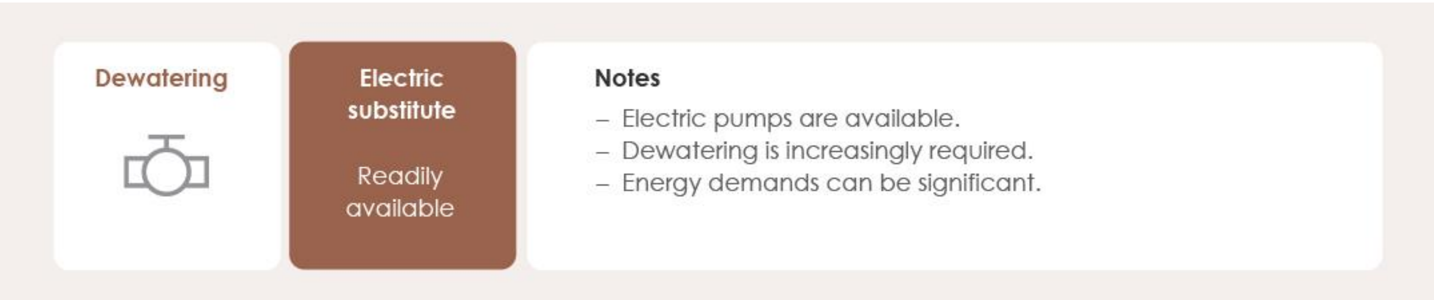


Figure 42: Summary of dewatering decarbonisation

Case studies

Case study K: Battery technology for heavy vehicles – 3ME Tech

3ME Technology (3ME Tech) have developed a scalable and powerful energy-dense lithium-ion battery system which can replace diesel-powered engines used in mining and defence vehicles, with battery electric systems, thus cutting emissions and creating safer and more efficient mining operations [74]. According to 3ME Tech, its Bladevolt® battery system allows for remote performance monitoring of the battery pack, as well as a modular design that is powerful enough to transform a 20-tonne loader into a fully electric vehicle [75]. The technology can also be scaled to fit a variety of applications including light vehicles, personnel carriers, load haul dump vehicles, and integrated tool carriers. 3ME Tech's battery system incorporates novel safety features to prevent thermal runaway, which is extremely beneficial for underground mining [75].

Figure 43: 3ME mine vehicle (image courtesy of 3ME Tech)

The Bladevolt® battery system has already been successfully retrofitted into underground mining equipment [75]. 3ME Tech has been backed by the CEFC and Australian Business Growth Fund (ABGF) with a $5 million and $15 million investment, respectively.

Case study L: BEVs – IGO + Barminco + Safescape + Normet

IGO, in collaboration with Barminco, has successfully trialled Safescape's Bortana Battery Electric Light Vehicle (BELV) at IGO's Nova mine [76]. The trial is part of IGO's target to fully electrify its mine plant and vehicles while setting the path for studying the use of bigger classes of equipment in underground mines [77]. The EV is designed specifically for underground use and has numerous safety and efficiency improvements for underground mine operations. Electric vehicles produce zero emissions and less heat than diesel vehicles, allowing underground operators to work without the risk of harmful particulate inhalation (produced when diesel is combusted) [76].

Figure 44: Safescape's Bortana BELV being trialled at IGO's Nova mine (image courtesy of Barminco)

IGO and Barminco have also trialled the Normet underground EV, at the Nova mine. The trial used Normet's *Charmec MC 605 VE SD* for underground operations [78]. This was IGO's first heavy-duty BEV at Nova and was used as part of a three-month trial for explosive charging operations underground [77]. Normet's SmartDrive technology features fast charging capability for its high-torque electric motors. The trial has delivered positive feedback, according to Barminco [78].

Both trials have demonstrated a successful collaboration with a clear focus on innovation. IGO have assessed that one of the most effective ways to both minimise emissions, achieve IGO's carbon neutral strategy, and improve safety and productivity, will be through the future electrification of their mine plant and vehicles [77].

IGO and Barminco are both part of the Electric Mine Consortium, which aims to decarbonise and electrify the mining industry, and are undertaking a number of trials to advance electrification and sustainability underground.

Mineral Processing

Summary

Where practical, sourcing energy directly or indirectly from electrical energy presents an opportunity to decarbonise a range of mineral processing activities. Stationary energy consumption for many mineral processing purposes, including physical processing (i.e. comminution), electrowinning, and some heating applications, is already electrified, as there are fewer energy storage limitations for fixed plant than for mobile equipment.

The capital intensity and maturity of the processing changes required to implement decarbonisation strategies vary across each commodity and process. The appropriate decarbonisation strategy will depend on the availability of resources and technology, and the embodied emissions within the processes required. This guide presents a high-level assessment of key decarbonisation opportunities across four high-level groups of processes.

Figure 45: Summary of electrification and decarbonisation potential for forms of mineral processing

Technology insights

Physical processing

- **High degree of existing electrification:** Physical processing activities and equipment are already largely electrified and can be paired with renewable energy to support accelerated decarbonisation.
- **Load-management potential:** In energy systems with high renewable energy penetration, for physical processing, demand-response techniques typically require flexible milling and crushing production capability to match the availability of renewable energy.
- **New comminution technologies:** Solutions such as vertical roller mills may provide greater flexibility to support higher renewable energy penetration.

Electrometallurgy

- **Complete electrification achieved:** Electrowinning uses electrical energy and therefore can be completely decarbonised when paired with renewable energy generation and battery storage.
- **Load-management potential:** There is potential to capitalise on flexible production and management potential with enhanced demand-response techniques, by matching the electrowinning load with the profile of renewable energy generation.

Hydrometallurgy

- **Little or no direct emissions:** Hydrometallurgy consists of many liquid and aqueous solution processing techniques and as a result is rarely a source of significant direct process emissions. Pumps and aerators providing motive force are already electrified.
- **Potentially significant source of embedded emissions:** The upstream production and transportation of the chemical reagents may produce significant Scope 3 emissions.

- **Work with suppliers:** It will be necessary to work with suppliers to signal and encourage zero carbon production of required process inputs, particularly where organisational targets require Scope 3 emissions inventories and decarbonisation.

Pyrometallurgy

- **High-temperature processes can be electrified**: High-temperature pyrometallurgical applications are challenging to decarbonise but are increasingly able to be heated directly with electricity, or indirectly through green hydrogen.
- **Consider hydrogen for chemical reduction**: Depending on the process used, replacing carbothermic reduction techniques with hydrogen reduction techniques is becoming increasingly feasible.

Practical considerations

- **Decarbonise electricity and electrify first:** Decarbonisation of mineral processing can be enabled by shifting energy consumption to electrical energy, which can be supported by renewables, load management and energy storage.
- **Green hydrogen can provide flexible electricity:** Green hydrogen can provide an indirect way to use renewable electricity supply. While it may be less efficient than direct electrification, the flexibility of this stored energy can help unlock further electrification solutions.
- **Investigate alternative processing solutions:** For hard-to-abate processes, alternative inputs such as hydrogen to replace coke for reduction, or recovery and reuse of waste heat, may achieve the desired product.
- **Consider future energy requirements:** As demand for minerals and metals increases, the depletion of ore bodies will accelerate. The quality of orebodies will continue to diminish over time and as a result, the associated energy required to process ore and deliver the same amount of product will increase.

Processing in brief: Mineral processing

Processing material to higher value products and moving the material down the value chain typically involves several steps and the technologies and processes required to do so can be diverse and complex.

This section provides a starting point from which to consider the decarbonisation of mineral processing. A diverse range of processes are grouped into four high-level categories rather than capturing specific sub-processes in detail. The categories of **Physical Processing** (including comminution), **Electrometallurgy, Hydrometallurgy** and **Pyrometallurgy** are intended to incorporate the common forms of processing across major Australian commodities.

Processing: Inputs and outputs

A high-level framework demonstrating emissions sources within mineral processing is illustrated in Figure 46, which reflects the simplified inputs and outputs of a process. As this is a general depiction, there will also be additional waste products, ancillary materials, and flexibility over the boundaries of the process specific to each application.

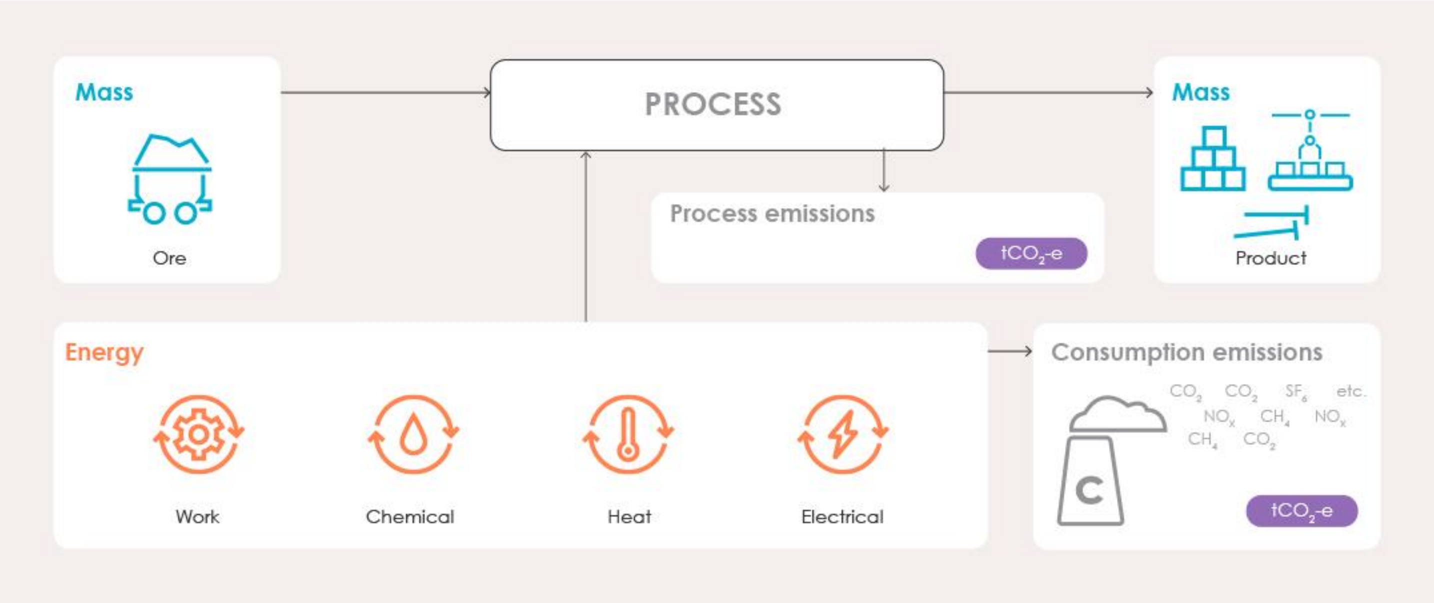


Figure 46: General depiction of a process; mass in and mass out, with the mass transformed by energy. Emissions may be produced directly from the process in addition to the process' energy consumption

Emissions sources within the processing cycle are associated with energy consumption, embodied within inputs (such as those embodied in the production and transportation of chemical reagents: Scope 3) and in some instances are directly emitted because of the process itself. Decarbonisation of mineral processing focuses on maintaining the inputs and outputs while eliminating the process, input, and consumption emissions.

Source of emissions: process, consumption, and embodied

The emissions associated with energy consumption often represent the largest source of emissions in a mining and processing operation. As reflected in Figure 47 and Figure 48, comminution (a form of physical processing) is one of the largest consumers of energy in a processing operation. Where these processes are or can be electrified, transitioning to a renewable energy supply presents an opportunity for decarbonisation. For some processes, however, there will be significant and unavoidable direct process emissions associated with the processing of ore.

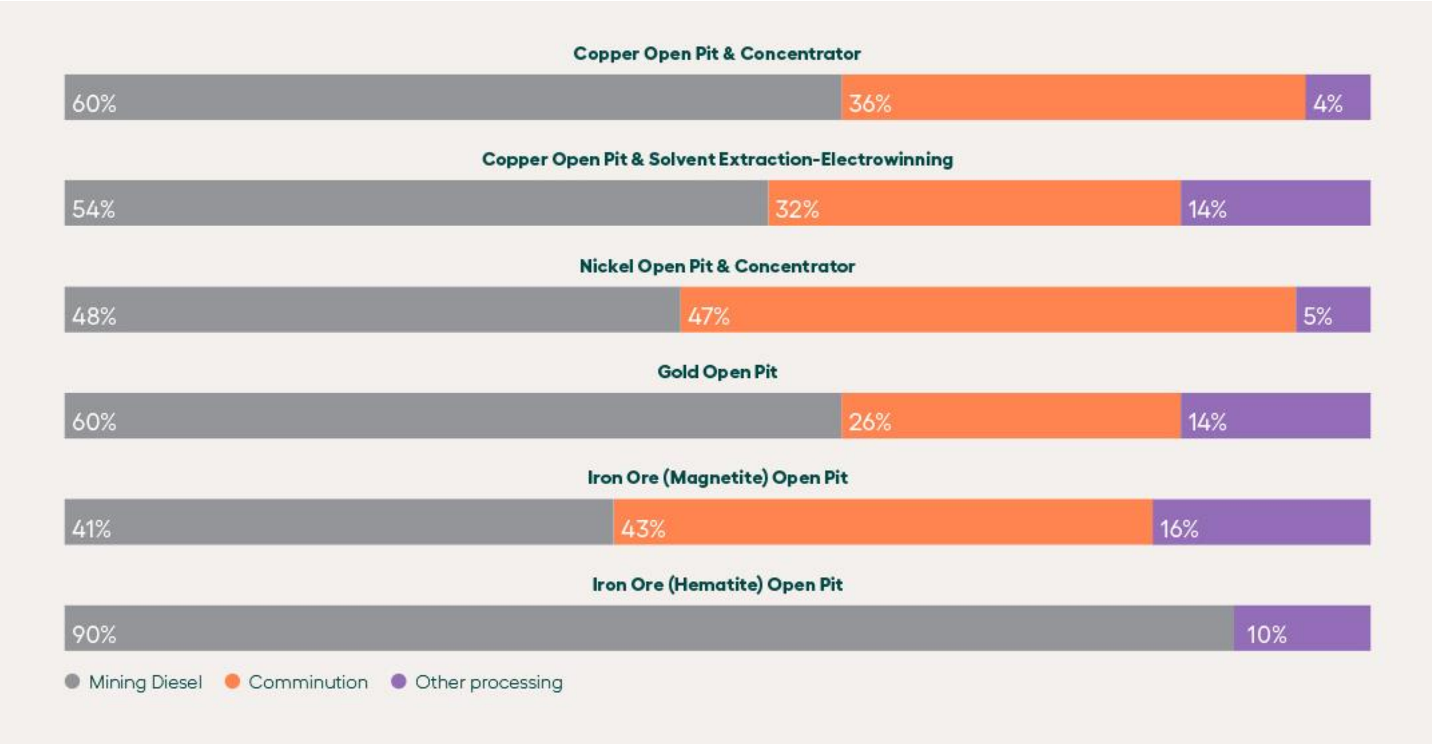


Figure 47: Energy profile of various open pit mines. Source: Engeco 2021 **[19]**

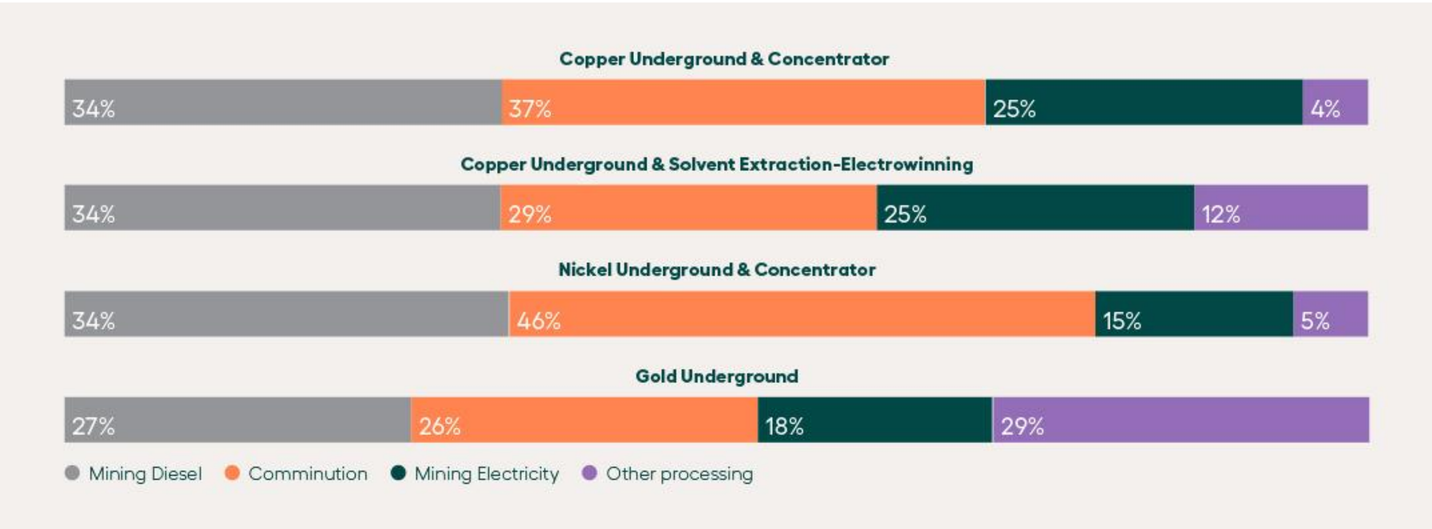


Figure 48: Energy profile of various underground mines. Source: Engeco 2021 **[19]**

The abatement of process emissions is significantly more difficult and typically requires a structural processing change. To distinguish this step change, three types of emissions are defined:

- **Process emissions:** Embodied within the material that are then expelled from the ore as a part of the processing. An example is calcining, which is the liberation of CO_2 from a mineral such as calcium carbonate ($CaCO_3$).
- **Consumption emissions:** Emissions associated with the consumption of fuels and the direct usage of energy through work and heat, see below.
- **Embodied emissions (Scope 3):** Emissions embodied within upstream production and/or transportation of materials required for processing, such as chemical reagents for hydrometallurgy.

Forms of processing and source of energy

Each of the four categories of processing outlined above and the energy types they consume can be seen in Figure 49. This is a non-exhaustive listing of processes, as there are many sub-categories of processes falling within each category.

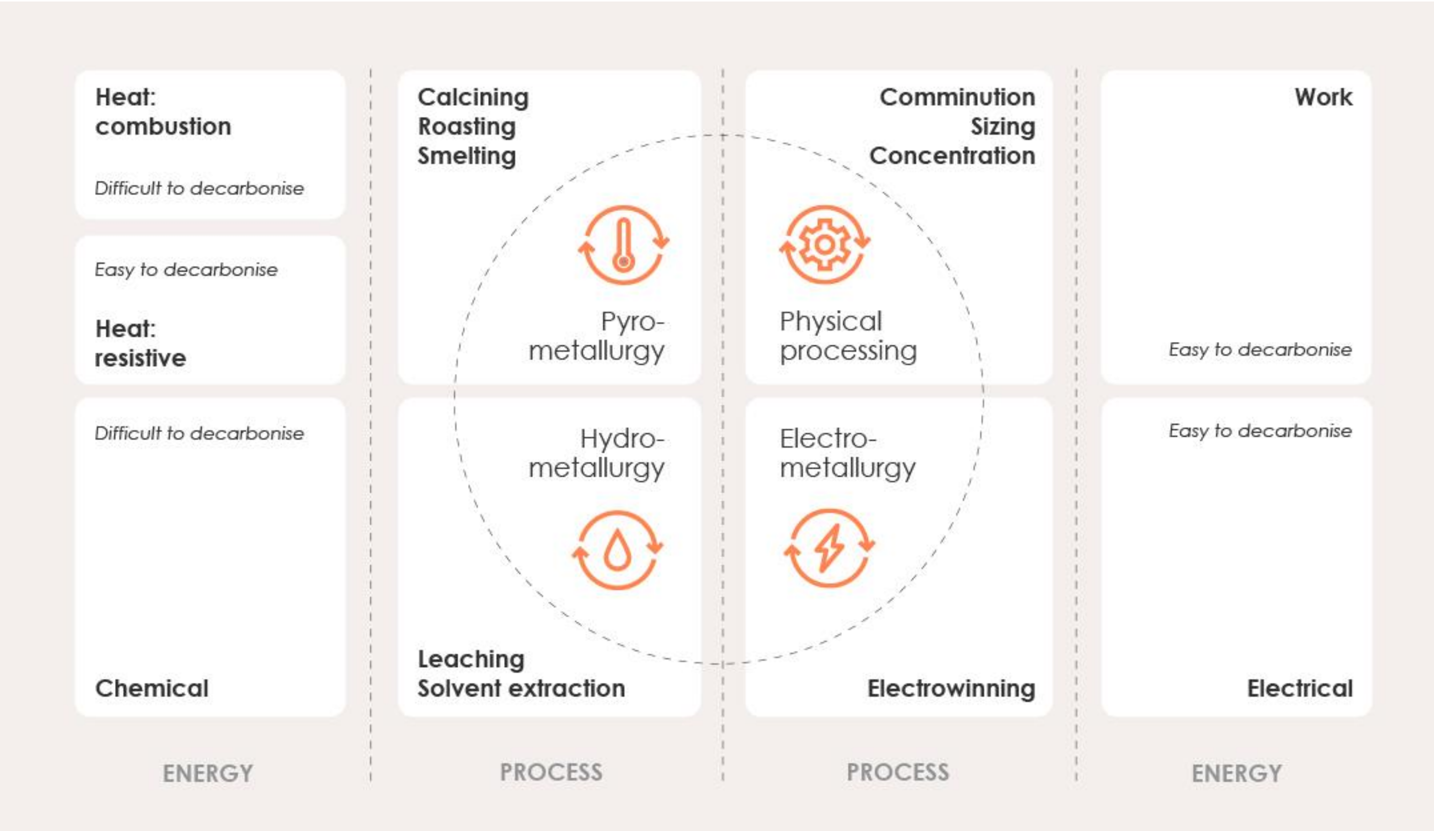


Figure 49: Summary of high-level categories of mineral processing, process examples, primary energy source and decarbonisation potential. Note: there are some physio-chemical processes such as flotation (a sub-process within Concentration) which are aggregated for simplicity.

Identifying the form of energy used within a process is the first step to determining the appropriate decarbonisation solution. Physical processing and electrowinning can be readily decarbonised through electrification, while hydrometallurgy and pyrometallurgy require greater attention.

Electrification strategies

Direct electrification

As summarised in Figure 49, electrification of all possible energy in a processing context is a leading decarbonisation strategy. Driving motors, such as in mills, with electrical energy is already best practice and there will be many other forms of equipment and processes that can be readily and easily electrified, including chemical energy. Energy-intensive, high-heat processes will be more challenging, and solutions outside of electrification will need to be considered.

Indirect electrification

Taking a higher systems view assists finding where chemical and heat energy can also be electrified. Resistive heat is the foremost method for electrifying high-temperature heat, but there may be contexts where this cannot be achieved. If combustion is required, electric energy may be moved from a direct form of energy supply to an indirect form.

Green hydrogen can be utilised as an indirect form of electrification. While less energy efficient due to conversion losses, it is more operationally flexible. Green hydrogen is produced from renewable electrical energy via electrolysis. Using this building block to move electrification into the realm of chemical energy will further enable deep decarbonisation. Likewise, if resistive heat is not possible but green hydrogen could be a substitute, the green hydrogen may be directly combusted to supply heat and therefore offer a method of electrifying heat requirements.

Recovery of waste heat

Energy efficiency projects such as waste heat recovery are an important and often economical early step in a decarbonisation journey. Waste heat recovery reduces emissions by reducing the consumption required for the delivery of the same quantity of heat. Many energy efficiency projects can be financially beneficial, although the opportunity cost of such actions should also be considered. Installing marginally more efficient gas burners may lock in a carbon-intensive technology at a high cost, where it may be more beneficial in the long-term to aim for the substitution of a gas burner with a zero-carbon alternative.

Demand response and load management

Demand response refers to the scaling up or down of electricity consumption to match the available electricity supply. For certain types of processing, it becomes strategically important to be able to control electricity demand. For processes such as aluminium smelting, this will be very difficult due to the constant requirement for heat and high consequences for power loss (such as molten aluminium solidifying in tanks and pipes). For processes such as electrowinning, however, the process can be set up to match the availability of renewable energy [79]. It may be more plausible to curtail production to match the availability of renewable energy than it is to pursue complete decarbonisation for every hour of the year. This is dependent on the process, however, as the impact of power loss can vary from a slight inefficiency in yield, through to damage to a processing plant.

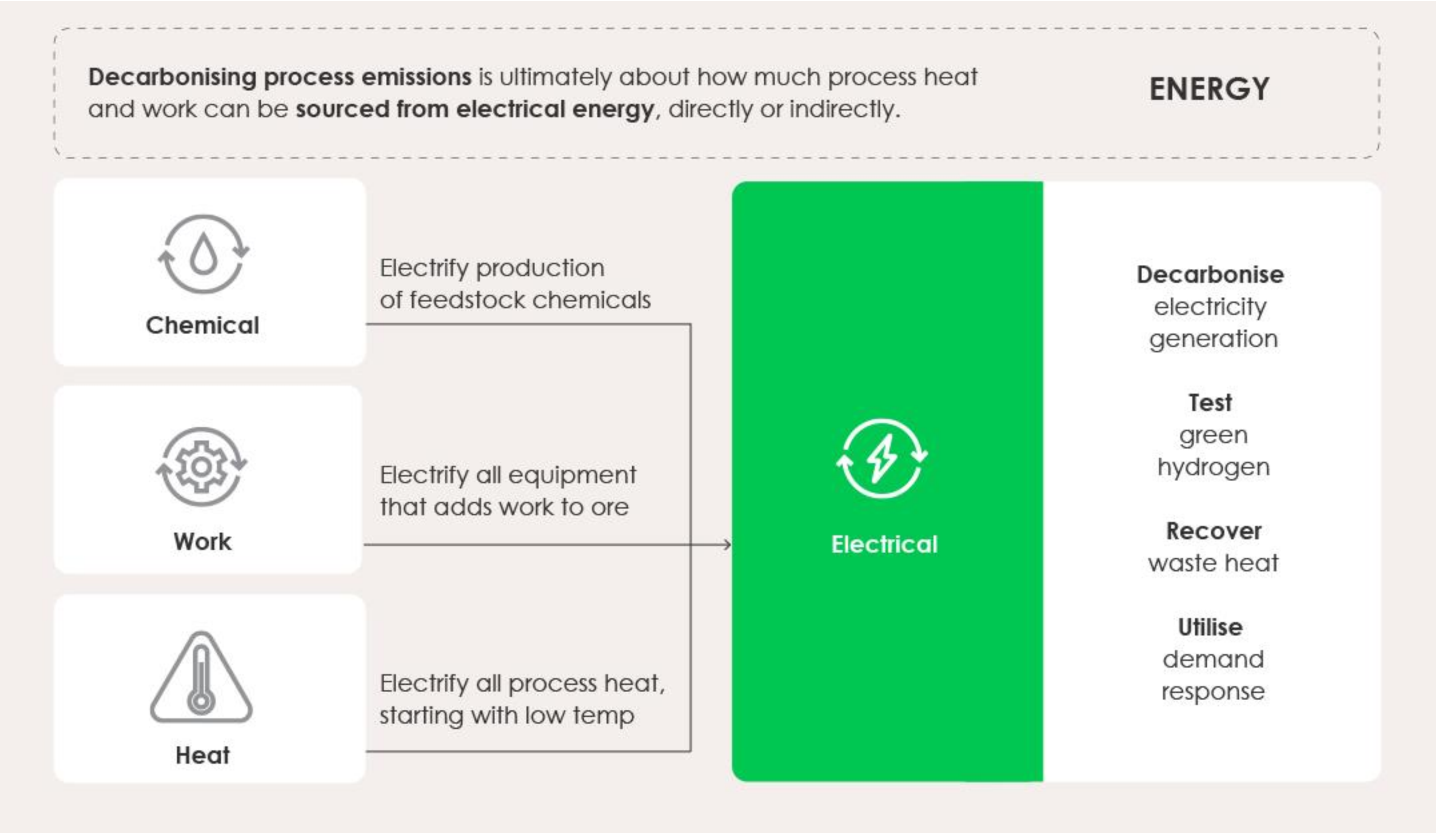


Figure 50: Electrification of energy requirements where possible is a leading decarbonisation strategy

Process assessment: electrification of mineral processing

As discussed above, the ability to efficiently decarbonise processes will largely be a function of how much energy within a process can be electrified. Electricity is easily decarbonised compared to other sources of emissions and as a result, is advised to be a priority for decarbonisation strategies. As indicated in Figure 49, this will be difficult in some applications, particularly where direct combustion of fossil fuels is used to create process heat, which can be challenging to substitute with electrification.

When considering the electrification and decarbonisation potential of mineral processing categories, relevant factors are summarised in Table 12 below.

Table 12: Factors considered for the decarbonisation potential of mineral processing categories

Factor	Description
Current electrification	This category represents the degree to which this process is electrified.
Scope for direct electrification	Including already electrified processes, this category represents how the energy used can be directly sourced from electrical energy, such as resistive heating or work from electric motors.
Scope for indirect electrification	Indirect electrification involves using electricity to produce a fuel that stores chemical energy (such as green hydrogen) for use in the process.
Load flexibility	Specific for mineral processing, demand response requires load flexibility. Some processes are operated in batches and some in continuous flows. This category represents the ability for the processing ability to be turned on or off as required to capitalise on lower energy costs pairing with the renewable energy generation profile.

A high-level overview of each category of mineral processing can be seen in Table 13. Physical processing and electrometallurgy are largely already electrified and thus the scope for indirect electrification is not applicable.

Table 13: Summary of decarbonisation of mineral processing

Process	Current Electrification	Direct Electrification Potential	Indirect Electrification Potential	Load Flexibility
Physical processing	Very high	Very high	Already directly electrified	Moderate
Electrometallurgy	Very high	Very high	Already directly electrified	Very high
Hydrometallurgy	Low	Moderate	Very high	Moderate
Pyrometallurgy	Moderate	High	Very high	Low

Physical processing

Crushing, milling, and sizing ore requires a significant amount of work in breaking up the material into ever smaller materials. Most of this work is ultimately driven by electrical energy, such as driving centrifugal pumps that move the slurry, and the motors that rotate the mills. There are some exceptions, including physical separation techniques that rely on surface chemistry and surfactants, such as flotation. Despite this, physical processing is mostly already, or is easily electrifiable.

Where physical processing is electrified, decarbonising the electricity supply (see Stationary energy) can support zero-carbon mining, which will be best achieved through load flexibility, matching production schedules to the availability of renewable energy. For examples, refer to OZ Minerals' Vertical Rolling Mill (Case study O). A stylised example can be found in Figure 8 where electricity demand perfectly matches available VRE.

Electrometallurgy

Typically, electrowinning is the selective metal deposition on cathodes within an electrochemical cell. This requires the metals to be in an aqueous solution, and is typically applied after hydrometallurgical processes such as leaching.

As an existing electrical process and as with physical processing, electrometallurgy can be readily decarbonised through transitioning electricity supply to renewable energy generation.

To maximise the impact of renewable energy supply on emissions reduction, flexible load management through demand response can be achieved, particularly given the batch nature of electrowinning which allows the load to easily be matched to the availability of renewable energy.

Hydrometallurgy

The potential for decarbonisation within hydrometallurgy depends on the specific process and reagent materials used. Hydrometallurgy uses leaching and solvent extraction to separate metals from their ores. From a process perspective, this often involves chemical energy requirements resulting in low potential for direct electrification.

Indirect electrification is possible when considering the energy used to produce the chemicals that comprise the solvent and solution. The energy embedded within this process is difficult to visualise but is effectively a form of chemical energy. Taking gold cyanidation as an example of leaching, cyanide is used as a chemical reagent within the leaching solution to selectively dissolve the gold out of the ore. There is no direct addition of energy beyond the stirring, however, the energy used within this reaction was added several steps before leaching during sodium cyanide production. The process is simplified and shown in Figure 51.

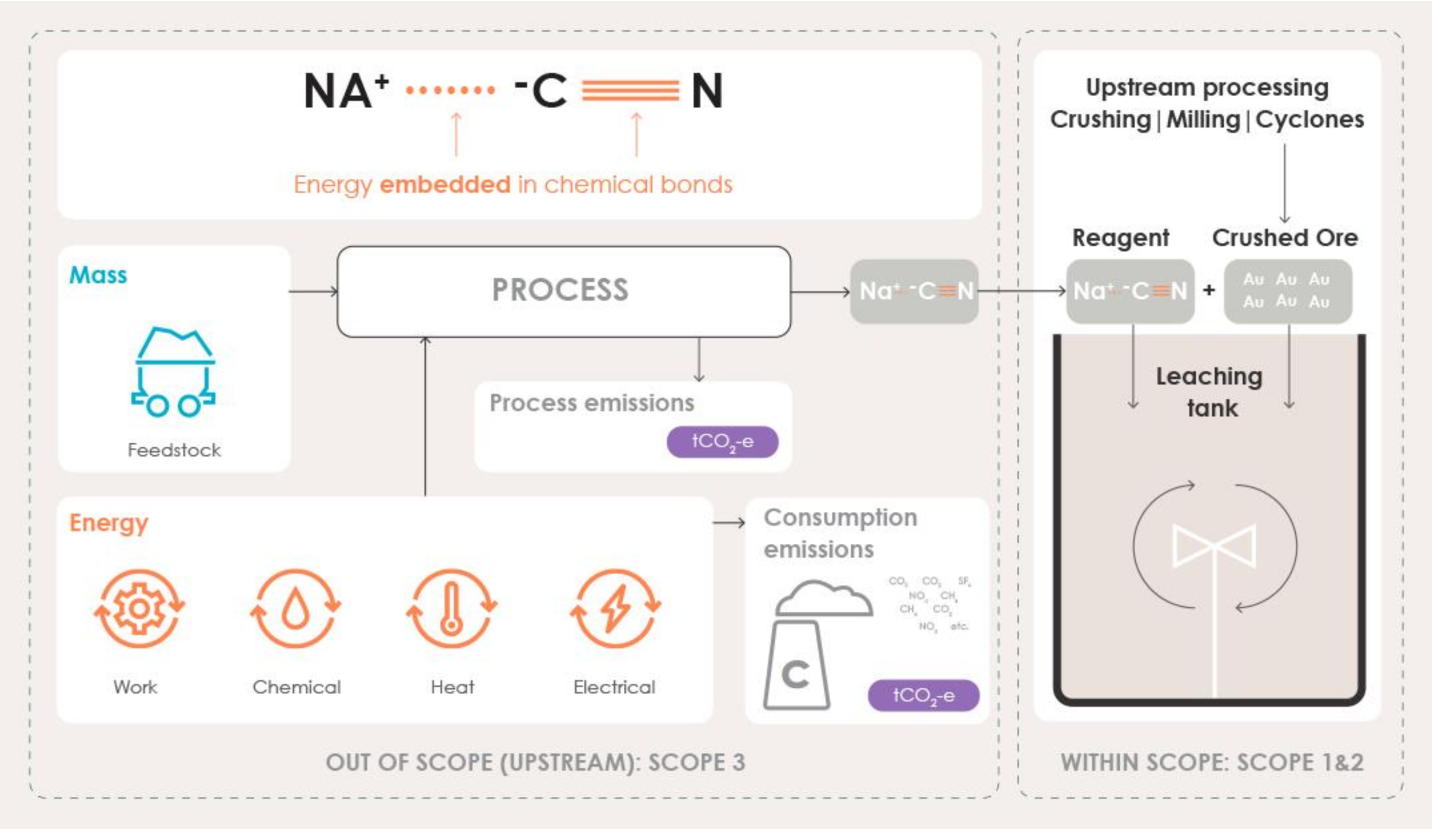


Figure 51: Description of emissions within a hydrometallurgy process. This specific example is cyanidation in gold processing

Before cyanide arrives at this process, it brings a high degree of embodied emissions from the energy required for its upstream production. These embodied emissions would not be calculated within Scope 1 and 2 emissions for the mining company. However, increasing pressure is mounting for organisations to work with suppliers to address Scope 3 emissions.

Decarbonising hydrometallurgy is readily achievable for Scope 1 and 2 emissions, as there are few emissions associated with most hydrometallurgical processes. While there may be some heating required, it will be easily electrified due to the low temperature. As pumping and stirring is an electrically driven activity, this could easily be decarbonised through renewable energy.

Removing Scope 3 emissions will be more challenging and working with suppliers to minimise emissions associated with embodied chemical energy will be essential.

Pyrometallurgy

Pyrometallurgy comprises the processes of heating a material to a temperature of decomposition, oxidation, reduction, or melting, encompassing the highest temperatures found in mineral processing. As a result of this heat being reached by emissions-intensive combustion, pyrometallurgy represents the largest source of emissions in mineral processing. Typically, direct resistance heating, gas, coking coal, and other carbon-intensive materials have been used to reach these temperatures. Decarbonisation of pyrometallurgy is rated as moderate for the current state of electrification as although most heating occurs through combustion, there is also a long history of electric smelting [80].

There are four main forms of pyrometallurgy – calcination, roasting, smelting and some types of refining. Pyrometallurgical processing is typically required for metals within their oxide or carbonate state (Fe_2O_3, SiO_2, TiO_2, $CaCO_3$, etc.). The processes involve a range of chemical reactions and thermal decompositions, with a range of gaseous and solid waste products.

As high-temperature requirements are often met by fossil fuel combustion, calcination and smelting can have significant process emissions and be very difficult to directly decarbonise. In combination with the high temperatures required, the decarbonisation of pyrometallurgical processes currently represents the largest barrier to the complete decarbonisation of the mining value chain.

Electrification of heat

While electrification of process heat is possible, it becomes increasingly technologically and commercially difficult the higher the temperature requirement, and may not be immediately achievable in all applications. As shown in Figure 49, there are direct and indirect ways to electrify heat.

Resistive heat has been used in many contexts and electric smelters have been active for more than 100 years [81]. Despite many economic and technological changes over this period, electric smelters remain well established. Significant advances are being made in the direct electrification of pyrometallurgy through various projects, including ELYSIS from Rio Tinto [82]. Consequently, the potential for direct electrification remains high for many heating processes.

Indirect electrification also remains an option. The usage of e-fuels such as green hydrogen or ammonia may be able to be directly combusted to produce the required heat. This would be determined by balancing transport and storage costs with the higher costs per unit of energy of indirect electrification.

The potential for load flexibility may be limited due to the risk of solidification of molten product in some processes, requiring power to be maintained to prevent uncontrolled cooling.

The challenge with electrification of pyrometallurgy is largely the step-change in electricity requirements. Direct electrification will lead to an overall reduction in primary energy consumption, but there will be a substantial increase in electricity generation and required infrastructure. The capital expenditure required to deliver adequately sized, new electrical infrastructure may be a challenge for junior to mid-tier mining operations. As renewable energy continues to reduce in price, the economic benefits of electric pyrometallurgy will increase.

Chemical reduction in pyrometallurgy

In some forms of pyrometallurgy, such as carbothermic reduction, carbon plays the chemical role of a reductant. This process is one way of expelling oxygen from the mineral, combining it with the carbon to be expelled in the form of CO_2, the most abundant GHG.

In this instance, the issue is not just one of temperature but also a need to substitute a chemical reductant. An example of how the reduction capabilities of carbon have been substituted with another fuel type is in the burgeoning green steel industry. One of these methods is Svenskt Stal AB's (SSAB) HYBRIT technology, which substitutes carbon for hydrogen as a reductant. An overview of this process can be seen in Figure 52.

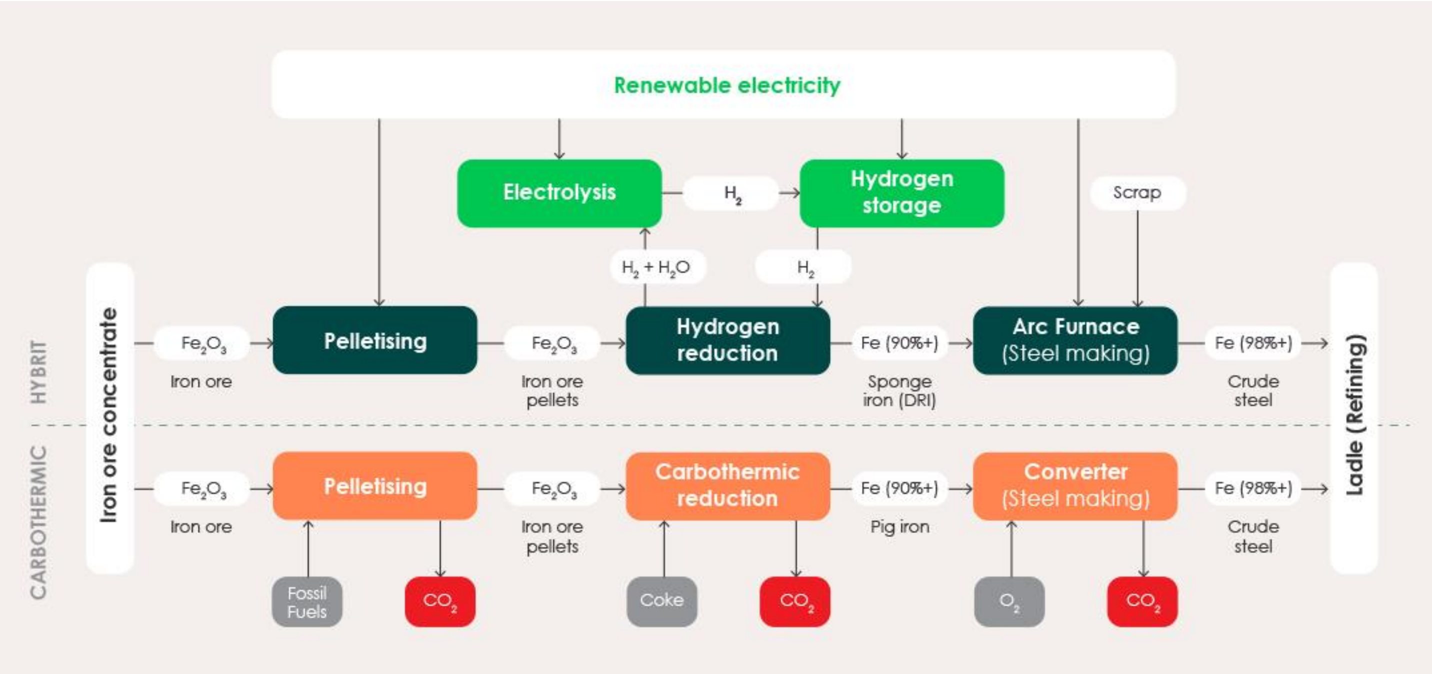


Figure 52: Overview of SSAB's HYBRIT process. Top half is the HYBRIT process, and the bottom half is the traditional carbothermic process

Within the HYBRIT process, the chemical energy used in the reduction of the iron ore is substituted. Where the traditional technique of steelmaking involved the introduction of coke to reduce the steel, in the HYBRIT process, green hydrogen plays this role. This is an example of indirectly electrifying even the chemical energy required to reduce the iron ore into steel.

Case study M: MRIWA Green Steel Challenge – this question is not 'is it possible', but rather 'how to make it possible'

With the steel industry causing 7 per cent of global CO_2 emissions, there is a significant focus on the development of green steel. WA has significant under-utilised magnetite resources and potential green hydrogen production capacity, enabling the State to participate in the emerging green steel industry.

There are multiple scenarios through which WA could do this, including:

1. Continuing to export iron ore, creating green hydrogen and exporting overseas for steelmaking.
2. Producing direct-reduced iron locally, initially using gas-based direct reduction then subsequently through hydrogen direct reduction, and exporting overseas to be refined to steel.
3. Producing steel locally, exporting semi-finished products for overseas fabrication.

Work is underway into the viability of sustainably processing WA iron ore to green steel, or to produce the necessary inputs for green steel. Research proposals are also welcomed for grant funding. For details, visit: www.mriwa.wa.gov.au.

Other considerations for decarbonising mineral processing

Impact of diminishing ore grade

As demand for many metals increases, depletion of ore bodies will accelerate. Over time the quality of ore bodies will continue to diminish, and as a result, the associated energy required to deliver the same amount of product will increase. This can be seen in Figure 53, where a stylised figure highlights the relationship between ore grade and energy consumption.

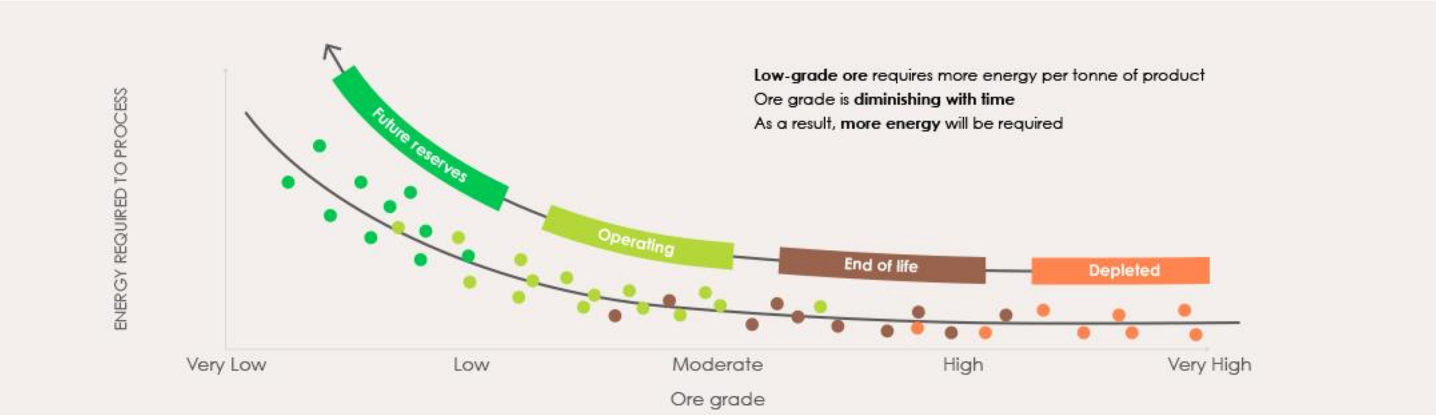


Figure 53: The impact of diminishing ore grade on energy demand over time. As ore bodies decrease in grade, the required energy to get the same amount of product will increase

In practical terms, the increased energy consumption will occur over the entirety of the mining and processing value chain. Mines will run deeper, haul truck paths will be longer, and more processing will be required to deliver a viable product due to the lower quality of the ore.

As energy consumption increases, without decarbonisation of the entire value chain, the carbon liability will increase in step. This poses an opportunity for greater differentiation between competitors and therefore this risk is an opportunity for those who decarbonise operations – especially from the outset.

Carbon liability: Moving downstream

From a strategic perspective, moving down the value chain is an opportunity to capture more value. As economies of scale build around renewable energy hubs or resources, the economics of end-to-end production of commodities may become more favourable. By onshoring a higher degree of production, investments in local renewable energy and green fuel hubs may be leveraged to fully decarbonise the value chain. This provides greater control over the energy going into each product and reduces wasted energy on long-distance transport. In other words, onshoring more elements of the ore to product pipeline may add less carbon to the global carbon cycle.

From the perspective of carbon liability, as an organisation moves up or down the value chain, the volume of liable emissions also increases – Scope 3 emissions become Scope 1, moving them directly within the organisation's control and reporting liability.

Figure 54 shows how moving down the value chain, even with decarbonisation strategies in place, can lead to an increase in carbon liability. An important consideration is whether this increased risk is offset by the opportunities gained and value captured, from selling a lower carbon product.

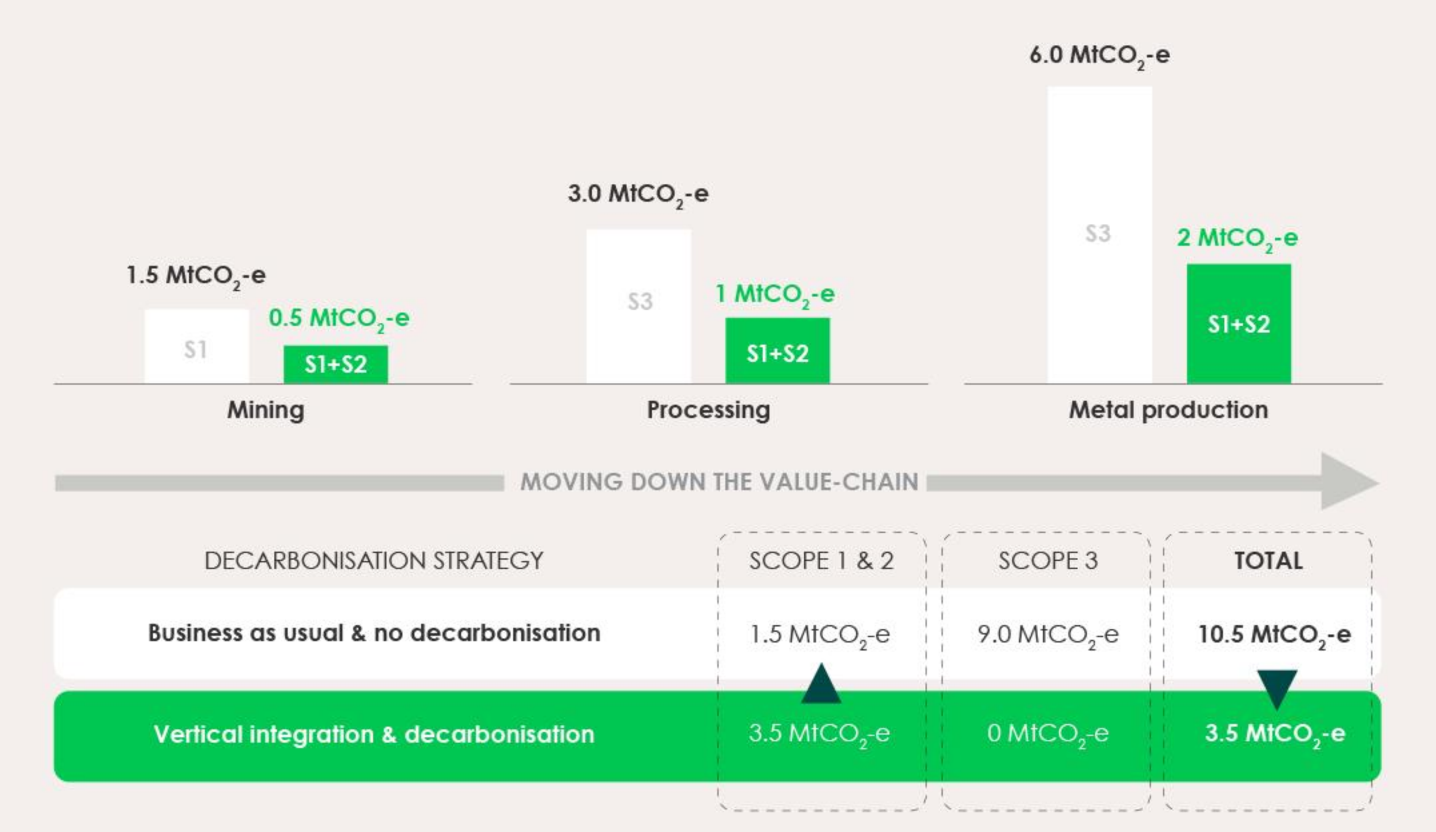


Figure 54: Moving down the value chain and carbon liability. Defining targets and metrics to measure decarbonisation impact is critical to avoiding undue carbon liability. [S1 = Scope 1 emissions, S3 = Scope 3 emissions].

If there is movement up or down the value chain, it is important to keep stakeholders engaged and understanding that while there may be an increase in liable emissions, the global benefit of such an action is net-reduction in emissions due to decarbonisation strategies.

Case studies

Case study N: Mechanical vapour recompression – Alcoa

Alcoa of Australia Limited (Alcoa) is currently conducting technical and commercial studies to adapt Mechanical Vapour Recompression (MVR) technology to their refining process [83]. Alumina refining accounts for approximately 24 per cent of Australia's direct, non-electricity (Scope 1) manufacturing GHG emissions, or 14 million tonnes annually [84]. MVR technology is well understood but has never been implemented within the alumina industry or used at large scale within Australia before. This project will trial MVR, using renewable energy to recycle waste steam that would otherwise be exhausted to the atmosphere [85]. If the feasibility studies are successful, Alcoa plans to install and commission, by the end of 2023, a 3 MW MVR module with renewable energy at the Wagerup Refinery, WA, to test the technology at scale [83].

Figure 55: Alcoa's Wagerup Refinery (image courtesy of Alcoa)

The total project cost is $28.2 million, with $11.3 million funded by ARENA [85]. The MVR technology powered by renewable energy could reduce an alumina refinery's carbon footprint by 70 per cent [85]. Using lower carbon alumina in smelting will help to reduce the carbon footprint of aluminium and hence reduce emissions down the value chain. If this trial is successful, it will provide an electrification alternative to fossil fuels for thermal demand requirements within the alumina refining process.

Case study O: Accommodating variable renewables – OZ Minerals

OZ Minerals' West Musgrave Project is positioning as a long-life, low-cost sustainable producer of minerals essential to a low carbon economy. Significant reduction in carbon emissions and power demand were factored into the pre-feasibility study stage through the adoption of vertical roller mills (VRMs) [86].

VRMs are widely used in the grinding of cement plant feeds and products, slag, coal, and other industrial minerals, with thousands currently in operation worldwide. The benefits of the mill include reducing power consumption, no ball charge grinding media required, higher flotation recovery and the ability to be ramped up and down easily without the risk of blockages common to ball mills, in response to the availability of low-cost renewable energy [87].

OZ Minerals has been able to achieve significant potential reductions in its emissions and power demand through the adoption of vertical roller mills as their grinding mill solution. The lower power usage has resulted in reduced operating costs, while the use of dry grinding from the VRM has also resulted in an improvement in nickel recovery [87].

OZ Minerals is also evaluating the inclusion of a third vertical roller mill (VRM) at its West Musgrave mine site, following a successful pre-feasibility study and has signed a "partnering agreement" with Loesche, a leading OEM in the field [87]. Increased silo capacity post-milling process could allow the additional VRM to be ramped up or down when additional energy is available to reduce the short-term battery requirements on-site and enable further energy management and emissions reductions.

Figure 56: Vertical roller mill at West Musgrave mine (image courtesy of OZ Minerals)

Case study P: Electric calcination – Pilbara Minerals + Calix

Commencing in July 2021, Pilbara Minerals and Calix have progressed a joint agreement towards the production of a mid-stream product for lithium batteries, a concentrated lithium salt. This project has seen recent advancements with the award of $20 million from the Modern Manufacturing Initiative (MMI) grant from the Australian Government, in June 2022, and progression towards commercial terms for the pilot facility [88]. Pilbara and Calix entered into a binding MoU setting out the key terms of a joint venture to market test samples, conduct Front End Engineering Design (FEED) studies and ultimately build a demonstration facility at the Pilgangoora spodumene mine in WA with the vision to produce a higher value lithium salt, while reducing carbon emissions.

Figure 57: Pilbara Minerals' wholly owned Pilgangoora Project, WA (Image courtesy of Pilbara Minerals)

The project is investigating processing fine, lower grade spodumene concentrate on site using renewable energy to create a low carbon, concentrated lithium salt. Calix's core technology involves a new type of kiln which is highly versatile and able to be electrically heated, making it renewable-energy-powered. The Calix calcination process is particularly well suited to fine spodumene feeds, allowing lower grade concentrates to be successfully treated and renewably powered [89].

Mineral carbonation and rehabilitation

Carbon capture and storage (CCS) is generally understood to mean technology that takes CO_2 out of the air, or flue gas, and stores it in geological formations, known as sequestration. A type of CCS, mineral carbonation is a naturally occurring form of carbon sequestration whereby minerals react with atmospheric CO_2 to combine into mineral carbonate. This natural process, also known as weathering, traps the CO_2 permanently into geological structures and in doing so, reduces GHG in the atmosphere. Enhanced weathering is further accelerating this process to meet 'additionality' requirements for offset standards.

Studies at BHP's Mt Keith nickel mine have demonstrated that this process has potential to sequester up to 39 ktCO_2-e per annum which was a significant proportion of the mine's total emissions (~11 per cent at the time of research) [90]. While this would be costly to deliver at smaller sites, to be able to establish legitimate carbon accounting practices, the research held implications for other operations with ultramafic tailings. Slowing the rate of waste deposit to 25 cm/year was one such method, as it allowed for the brucite held in the waste to fully capture the carbon (or carbonate) [90]. Spreading the tailings over a larger surface area would have a similar effect, although this may have negative environmental or social concerns.

Enhancing the speed at which this process occurs is known as enhanced weathering. This type of process acceleration can be done mechanically and chemically, including a microbial acceleration process injecting tailings with bacteria. An important, yet emerging research field investigates the ability of accelerating mineral carbonation to stabilise tailings containing harmful minerals such as asbestos. This research holds promise for the end-of-life of mines to more effectively remediate and stabilise tailings, as well as to sequester additional carbon permanently [91].

Financial and strategic instruments

A variety of financial and regulatory instruments can be used to support decarbonisation. These include compliance and voluntary certified carbon credits, also referred to as offsets and Australian Carbon Credit Units (ACCUs) in the Australian market, and market-based electricity decarbonisation instruments (RECs and LGCs), collectively referred to as "carbon instruments" in this report. Other opportunities arise through financial incentives to support the decarbonisation journey including through lower cost of debt and equity or through government grants.

Carbon instruments

There are many activities companies can undertake to reduce and avoid GHG emissions directly, though in some instances carbon instruments may be required to support progress towards decarbonisation.

Carbon instruments, such as high-integrity carbon offsets, may be used to manage residual emissions from hard-to-abate activities where technologies have not reached commercial readiness or where a company has been unable to put in place other measures, to achieve deep decarbonisation. Best practice offset usage is not mutually exclusive with direct abatement and offsets are intended to be phased out once available substitutes have been found.

Carbon offsets are generated by emission reduction projects that either remove or avoid GHGs, contributing to abatement outcomes in line with the ambitions of the Paris Agreement. Offsets also deliver co-benefits such as biodiversity outcomes, regional employment outcomes, and social benefits. The Australian Government regularly reviews the credibility of publicly available carbon offsets - eligible offsets need to meet integrity requirements under the Climate Active Carbon Neutral Standard to ensure they represent genuine abatement [92].

Carbon instruments are best seen as a supporting tool used to complement portfolio-wide decarbonisation activities. As highlighted by the GHG management hierarchy shown in Figure 58, compensating through offsets is the last step when all other options have been exhausted. Three drivers for the need for carbon instruments are discussed below.

1. To ensure market-based electricity is matched with renewable energy generation.
2. As a risk management tool.
3. To maximise local social and environmental benefits.

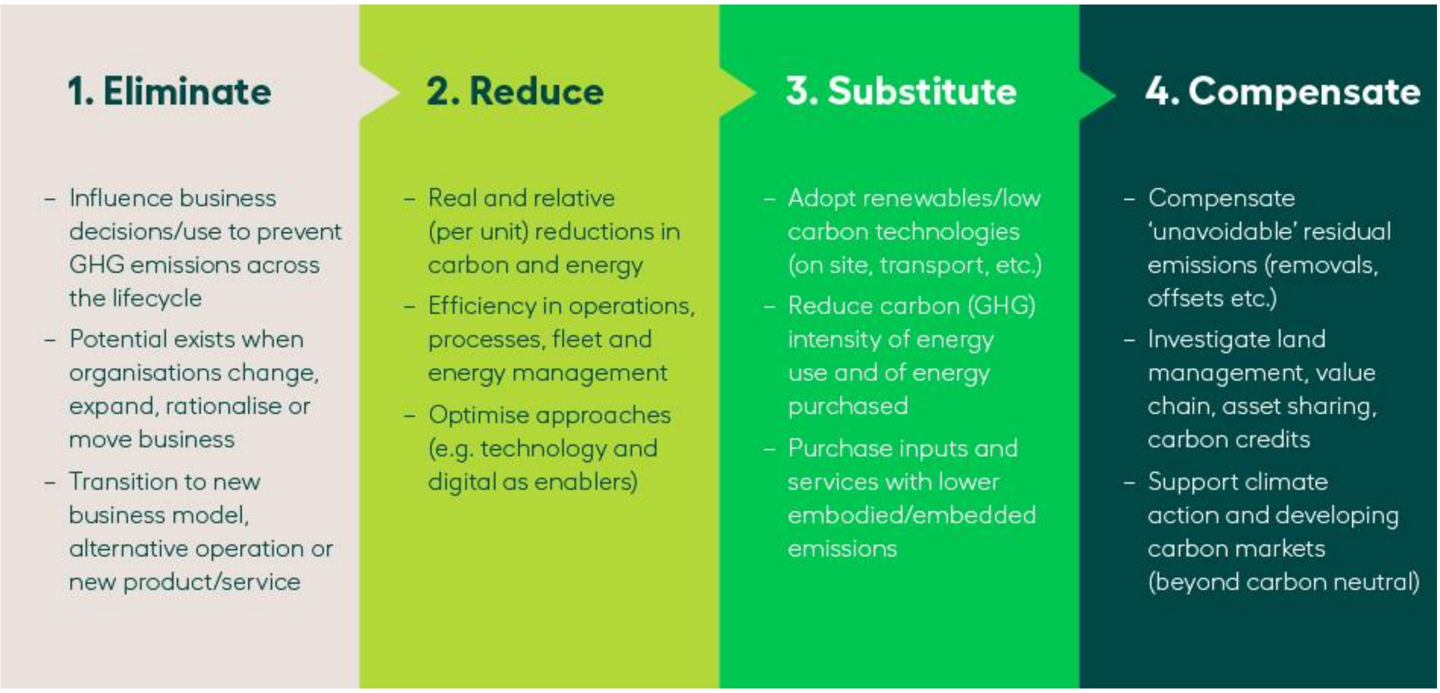


Figure 58: The IEMA GHG management hierarchy (updated 2020)

Market-based electricity

If the site is required to procure electricity from the grid, then to some extent it is reliant on the electricity market to support decarbonisation goals. RECs, such as LGCs in Australia, can be purchased to represent that the grid electricity used is matched with renewable electricity generation. This is discussed further in Appendix A.

Risk management tool

For some emissions, technology may be at a low maturity, or they may be more difficult to abate, which means there may be a buffer required to enable technology time to catch up. Thinking of offsets as a financial instrument to mitigate technology and market risk may help to achieve goals in a tolerable risk environment.

The GHG Management Hierarchy (Figure 58) can be likened to a risk management approach. The priority is first to eliminate these risks, then reduce them, substitute them and lastly, for residual risks a financial or contractual mitigation tactic is relied upon to compensate.

For example, given the volatility of commodity pricing markets, derivative financial instruments are used to mitigate price risks. In this case, the buyer or seller may seek to lock in a price for the commodity using financial instruments, meaning volatility is reduced. In this way, the derivative could not have substituted the transaction itself but played a role in reducing the risk.

Reaching decarbonisation goals comes with risk, and carbon instruments can help to mitigate this, however, they should not be the only strategy deployed. Carbon instruments may not be the least-cost approach to decarbonisation and the costs of carbon instruments can change significantly. For example, the Emission Reductions Fund (ERF) ACCU index was approximately $16.10 per tonne of CO_2-e in 2019, with the spot price reaching a high of $54.00 in January 2022 [93]. As decarbonisation goals become more commonplace, increasing demand for these instruments may put upwards pressure on prices [94] [95].

In the case where a proportion of hard-to-abate emissions, combined with low technology readiness provides heightened uncertainty, carbon instruments can play a risk mitigation role. This could be structured in a long-term procurement arrangement with a certified, high-quality supplier, to reduce the volume of emissions that is linked to short-term price changes.

Maximise co-benefits

Some carbon offsetting programs include environmental restoration activities that provide local employment, connection to country and culture and provide environmental (biodiversity) benefits beyond just sequestered carbon.

The mining community regularly experiences ESG scrutiny over its operations from stakeholders, often having to demonstrate how they are leaving the community and environment in a better place than when they found it. For this reason, where carbon instruments are utilised, certified carbon credit programs can be a useful way to achieve multiple ESG goals.

Healthy Country at the heart of any carbon credit program.

Healthy Country is a term that acknowledges the relationship between the health of the environment and social and cultural wellbeing of Aboriginal and Torres Strait Islander people [96]. This summarises the way carbon programs can achieve multiple benefits to the community at once if they are designed from inception not just to maximise carbon stored, but to maximise community and environmental benefits. As indigenous ranger programs around the country grow and gain more experience, an opportunity is created for the private sector to partner with local ranger groups to help provide long-term funding for relevant projects. These relationships are seen as long term and the project design must be led by the rangers and Elders to ensure Healthy Country is at the centre.

Many carbon credit providers are working on developing programs with this intent, and these high-quality programs do tend to come at a cost premium. Locally developed programs introduce a greater level of complexity, and areas things such as lease tenure (a minimum of 25 years is required) and the local climate (minimum amount of rainfall) will play into the extent to which units can be generated [97]. The overall benefits from a successful program, including a thriving local environment and community, may outweigh the cost premium.

Case study

Case study Q: Internal carbon price and carbon offsets – IGO

IGO completed a program of work during the 2021 financial year, to implement an Internal Carbon Price (ICP) to better understand the actual cost of emissions, price operational emissions, charge an internal carbon fee, and drive IGO's decision-making on low-carbon investments [77].

IGO has differentiated between an internal carbon price and a shadow carbon price. The ICP prices its Scope 1 and 2 emissions, which then creates a centralised decarbonisation fund that will be used to fund projects to reduce IGO's total carbon footprint [77].

For the 2022 financial year, IGO's ICP is $60/t$CO_2$-e, with the price being reviewed each financial year [77]. During the 2022 financial year, the decarbonisation fund is expected to allocate approximately $2–4 million [77]. Funds will be used to implement strategic decarbonisation projects at IGO's Nova Operation, invest in carbon removal and offset projects, accelerate IGO's understanding of supply chain and Scope 3 emissions, invest in research and development, and trial emerging technology and through pilot projects [77].

Figure 59: Sustainability Initiatives

IGO's strategy for carbon removal and offsets does not substitute the decarbonisation and GHG emission reduction of their operations, instead, it will be used in parallel while IGO is challenged by technology readiness and commercial availability [77]. IGO's offsets may be generated through projects in which GHG emissions are avoided, reduced, removed from the atmosphere, or permanently stored through sequestration. IGO will target the following carbon removal projects:

1. Emissions avoidance – reducing absolute emissions through project activity which would not have occurred under business-as-usual scenarios, preventing carbon that would have been released into the atmosphere.
2. Sequestration and natural carbon removal – removing carbon from the atmosphere and storing in plants and soils.
3. CCS mineral carbonation [77].

IGO has a limited life of mine at their Nova Operation, and low emission technologies are yet to be fully developed or economic, therefore IGO will need to have a greater reliance on offsets and carbon removal to help achieve net zero at Nova [77].

Financial incentives

While decarbonising a mine is capital intensive in the short-term, especially if converting or retrofitting brownfields operations, the results profiled in the **Roadmap Guide** will show a zero carbon mine can be NPV positive. Before this return can be realised, the capital to deploy these projects must be raised, which may seem like a prohibitive barrier for many junior and mid-tier miners. However, there are many financial incentives in play that create opportunities to reduce the long-term Weighted Average Cost of Capital (WACC), and in doing so achieve a better payback across the life of mine. Three main avenues to explore are:

1. Green loans and debt (CEFC and other financial institutions).
2. Green bonds.
3. Government grants.

As financial institutions and governments around the world shift their focus to achieving decarbonisation targets and deploy billions of dollars towards 'green finance', an avenue opens for those seeking to fund green projects. The demand for financial products with an environmental focus has been growing strongly, and miners of energy transition minerals with good ESG performance may have an ability to access deep pools of capital.

In Australia, the CEFC is playing a leading role in catalysing investment to accelerate decarbonisation through project finance, debt markets solutions such as green bonds, and equity instruments. The CEFC offers tailored investment solutions for renewable energy, energy efficiency and low emissions opportunities.

The CEFC aims to invest across the diverse resources sector. This includes supporting the evolution of new industries while also working with established producers to enhance mining operations, drawing on energy-efficient equipment, low emissions transport, and renewable energy.

- **Direct investments**: The CEFC's direct investments for clean energy projects include flexible debt and equity finance, or a combination of both, tailored to individual projects.
- **Debt markets**: The CEFC is a leading investor in Australia's emerging green bonds market, creating new options for investors, issuers, and developers.
- **Asset finance**: The CEFC works with banks and co-financiers to deliver discounted finance to businesses, farmers, and manufacturers for their small-scale clean energy investments.
- **Investment funds**: The CEFC invests in credible, established investment funds to co-deliver clean energy developments and is exploring resource-related opportunities.

Green loans and debt

Green loans, whether these be in the form of government-backed finance (through the CEFC or another financial institution), and the ability to access a lower interest rate on debt provided certain ESG criteria is met, are now becoming commonplace. One example is set out Case study R.

Case study

Case study R: Leveraging of green capital – Newmont

In March 2021 Newmont Corp executed a new US$3 billion sustainability-linked revolving credit facility, linking its ESG performance to the cost of debt, and allowing a cheaper interest rate in reward for high ESG performance [98]. Newmont's US$3 billion facility will be able to access up to 0.05 per cent lower interest based on ratings from MSCI and S&P Global through their respective sustainability performance indices. If rated AAA (or above 90) from each respective agency, Newmont will see a 0.05 per cent reduction in interest. For a rating above AA (or 88-89), this will entitle it to a 0.025 per cent reduction. However, if the performance drops to below BBB or BB this will result in increases of 0.025 per cent or 0.05 per cent respectively [98]. While this Sustainability Linked Loan (SLL) was the first of its kind for the mining sector, there are clear indications across the finance sector that these types of facilities and loan covenants are going to become the norm [99] [100].

Green bonds

In addition to accessing cheaper capital through debt facilities, new avenues are emerging through publicly listed debt, which are commonly referred to as 'green' through their links to sustainability performance.

Green bonds have been growing at a significant rate and the global sustainability bond market is projected to reach US$1 trillion by the end of 2021 [101]. There are two main ways these bonds can be considered 'green'. First, a prescribed 'use-of-proceeds' linked to a sustainable project or, as highlighted above, an ongoing performance rating against a fixed set of ESG criteria.

Use-of-proceeds bonds refer to funds that are attached to a specific use. Woolworths was the first major firm in Australia to issue these bonds, with $400 million in debt raised in 2019 to fund the installation of solar panels, energy efficiency retrofits and upgrading refrigeration solutions among its emission reduction measures [102].

In the mining sector, FMG is positioning itself to issue public bonds to raise capital [103]. Newmont succeeded with the first 10-year, climate-linked bonds issued for the sector in late 2021 [104]. The interest payable on Newmont's bonds is tied to its performance against Scope 1, 2, and 3 emissions targets over the next decade, and gender equity targets around women in leadership [104]. Should these targets not be met, the interest rate payable to investors increases, meaning a low cost of capital is achieved if they perform against their goals.

In addition to the growing bond market, the boom in ESG rating agencies indicates that investors in all shapes and sizes are making ESG-weighted decisions when allocating their capital. This means that quality ESG performance reporting, especially as it relates to climate change and emissions in the mining sector, will be crucial to the ability to secure and maintain capital.

Government grants

Although Government funding is cyclical and does not represent an ongoing source of finance, this has provided numerous companies around Australia a head-start in furthering their decarbonisation objectives. ARENA is one such organisation with the ability to finance projects that can demonstrate an ability to further both the technology and commercial readiness of decarbonisation methods. For more information on these grants, including the successful applicants to date, visit the ARENA website [105].

Various State-based grants are also available to support decarbonisation in mining, including research grant funding offered by MRIWA, WA's research institute for mining and minerals research [106].

Building the roadmap

As this report demonstrates, a range of low-risk technology options exists to decarbonise mining operations, with several emerging technologies also showing potential.

Some common themes arising from this analysis provide guidance for mining companies seeking to identify potential decarbonisation projects in their business:

- **Plan to save emissions and cost:** Mine planning is an important risk mitigation measure to ensure mine design is compatible with low emissions technologies, avoiding sunk costs and maximising life-of-mine returns.
- **Decarbonise electricity and electrify first:** Electrification and application of renewable energy addresses a large part of the immediate decarbonisation challenge and creates opportunities for ongoing electrification of other activities. Electrification opportunities are available in material movement, in-mine operations and mineral processing.
- **Coordinate infrastructure investment:** Combine new electrification infrastructure investments with other relevant decarbonisation initiatives to maximise value, whether in designing new operations or retrofitting existing approaches.
- **Invest in material movement:** As the scale of material movement emissions is significant, decarbonisation of material movement provides a significant opportunity to become best-in-class, broadening investor appeal.
- **Green hydrogen can provide flexible electricity:** Green hydrogen can provide an indirect way to use renewable electricity supply. While it may be less efficient than direct electrification, the flexibility of this stored energy can help unlock further electrification solutions.
- **Address Scope 3 emissions:** For example, in explosives and reagents, especially where reductions in Scope 1 and 2 emissions are more difficult to achieve across the mining operation.

For junior and mid-tier mining companies seeking to capture the economic and sustainability benefits of our low emissions future, the next steps are to consider how the decarbonisation technology options outlined in this report can be applied strategically to create an asset-level decarbonisation roadmap.

CEFC, MRIWA and ENGIE Impact have collaborated on a complementary report to assist your business to consider how to explore the various decarbonisation pathways: *Mining in a Low-emissions economy: Roadmap to Decarbonisation*.

Roadmap to Decarbonisation will assist build an understanding of what to prioritise, and how to construct a range of decarbonisation pathways for assessment, using a simulated mining operation as an example.

The report can be downloaded via: **cefc.com.au** or **mriwa.wa.gov.au**.

Roadmap to Decarbonisation will assist build understanding on what to prioritise, and how to construct a range of decarbonisation pathways for assessment, using a simulated mining operation as an example

Appendix A: Knowledge essentials

Developing decarbonisation strategies will be supported by knowledge of some basic but fundamental concepts. Some of the language and concepts used throughout this *Decarbonising Mining* series are expanded upon below as a reference guide.

Emissions essentials

Greenhouse gases and the tCO_2-equivalent

The GHGs that are reported under the National Greenhouse and Energy Reporting Scheme (NGERS) include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulphur hexafluoride (SF_6) and specified kinds of hydrofluorocarbons and perfluorocarbons [107].

As there are many types of GHGs, there is a need to consolidate the impact on the climate into a standard metric. As CO_2 is the primary GHG, each GHG is indexed relative to the impact of CO_2. Global Warming Potential (GWP) is a 100-year or 25-year metric comparing the mass of emissions from another GHG over that time horizon to one tonne of CO_2 emitted. This is known as 'tonne of CO_2 equivalence', or tCO_2-e. Methane is 28 times more potent as a GHG than CO_2, while nitrous oxide (N_2O) is 265 times more potent over a 100-year period. Other GWPs can be found through the GHG Protocol and AR5 reports [108].

Scopes of emission

GHG emissions are classified into different 'scopes' to reflect the different levels of liability or responsibility for emissions. From the direct combustion of fuel to downstream emissions from a product's use, there is a continuum between 'direct' and 'indirect' emissions.

Figure 60: Description of scope of emission

The definition and implementation of scopes of emissions are regulated and should be defined in line with regulated definitions, such as from the Clean Energy Regulator (CER) [109]. Generally, Scope 1 and Scope 2 emissions are simple and well defined. Scope 3 emissions are more ambiguous, and care must be taken in defining the boundary of emission.

Emission accounting and certification

With the increasing scrutiny applied to carbon liability and climate risk, standards for emissions disclosure are also increasing. As the cost of carbon is internalised, accounting for carbon within business practice is becoming similarly stringent as financial reporting. Within Australia, if a threshold of energy and/or emissions is met, there is a requirement for ***regulated*** reporting under NGERS. In addition to this regulated scheme, there are ***voluntary*** disclosure schemes such as the CDP.

Regulated schemes

Under NGERS, the CER collects and constructs a national inventory of energy consumption and emissions. Regulated schemes such as NGERS are mandatory if a facility or corporate group meets reporting thresholds [110].

In addition to regulating Scope 1 and Scope 2 emissions, the CER administers the national Renewable Energy Target (RET) which enables the purchase and surrender of RECs (specifically LGCs) against Scope 2 emissions [111].

Voluntary reporting

Not all emissions are covered by an emissions and energy reporting framework. Whether it is regulatorily required or not, financial institutions require such information to make decisions. As a result, some form of voluntary reporting is increasingly expected. Such schemes include CDP or TCFD, which are globally recognised standards in emissions and climate change reporting. Whereas NGERS only requires Scope 1 and Scope 2 disclosure, CDP and TCFD expect Scope 3 disclosure as well.

While ambiguous in nature, Scope 3 emissions considerations are based on the Greenhouse Gas Protocol, an international body that supplies standards for GHG inventories and accounting. [112] Inventories for Scope 3 emissions, where required externally or by internal targets, should be set up in accordance with respected standards such as the GHG Protocol's Corporate Value Chain (Scope 3) Standard [113].

Fuels essentials

Energy content factor

Each fuel has its own Energy Content Factor (ECF) which represents the amount of usable energy within the context of its usage. This means that the ECF is context dependent. The default context for an ECF refers to combustion, especially if it is a liquid, gaseous, or solid fuel. Diesel has an ECF of 38.6 GJ/kL, which means for each kL of diesel consumed by a technology (specifically, combusted) there will be 38.6 GJ converted into heat or work.

The standard reference for ECFs within Australia is the NGERS determination, specifically Schedule 1. [114] To align with regulatory reporting, it is advised to use the regulated ECFs.

Emission factor

As with the ECF, each fuel has its own emission factor (EF). The EF represents the marginal rate of emission for a specific fuel. Stationary diesel has a regulated EF of 2.71 tCO_2-e/kL. This means for the combustion of one kL of diesel, there is 2.71 tCO_2-e of emission associated with that consumption.

There are regulated EFs and to align with reporting schemes like NGERS, it would be advisable to use regulated EFs.

Emissions benefit

A consistent process is required to calculate emissions benefit. The emission benefit is the net benefit of a project (or simultaneous group of strategies) compared to business as usual (BaU).

Following a change in consumption, energy or emissions, the emission benefit is the sum of the original and replacement abatement outcome, which represents the change in emissions from the abatement of the original fuel and the replacement fuel.

$$Emission\ benefit\ [tCO_2e]$$

$$= Abated\ emissions_{Original}[tCO_2e] - Abated\ emission_{Replacement}[tCO_2e]$$

The net benefit of the original and replacement emissions is based on the various physical properties of the fuel and technology. The abated emission from the original fuel is calculated by multiplying the abated consumption by the EF of the original fuel. This represents the emissions no longer produced. If consumption is reduced, it should be signed as a negative number.

$$Abated\ emission_{Original}[tCO_2e]$$

$$= -\left(Abated\ Consumption_{Original}\ [unit]\right) \times EF_{Original}\left[\frac{tCO_2e}{unit}\right]$$

The replacement emissions are signed as positive as there is an increase in replacement consumption.

$$Abated\ emission_{Replacement}[tCO_2e]$$

$$= Additional\ Consumption_{Replacement}\ [unit] \times EF_{Replacement}\left[\frac{tCO_2e}{unit}\right]$$

To calculate the additional consumption required, note that the same work or heat requirement is to be met by the new fuel and technology combination. To keep it generalisable, below is an equation to calculate the additional consumption required.

$$Additional\ Consumption_{Replacement}\ [unit]$$

$$= Abated\ Consumption_{Original}\ [unit] \times \frac{ECF_{Original}\left[\frac{GJ}{unit}\right]}{ECF_{Replacement}\left[\frac{GJ}{unit}\right]} \times \frac{Technology\ efficiency_{Original}\ [\%]}{Technology\ efficiency_{Replacement}\ [\%]}$$

A sample stylised calculation can be seen in Figure 61, where a diesel-powered ICE is substituted with a BEV powered by grid electricity (without REC procurement). Note the same work (1000 GJ) is performed by both the BEV and ICE technologies, with the replacement fuel calculated based on the efficiency of the replacement technology.

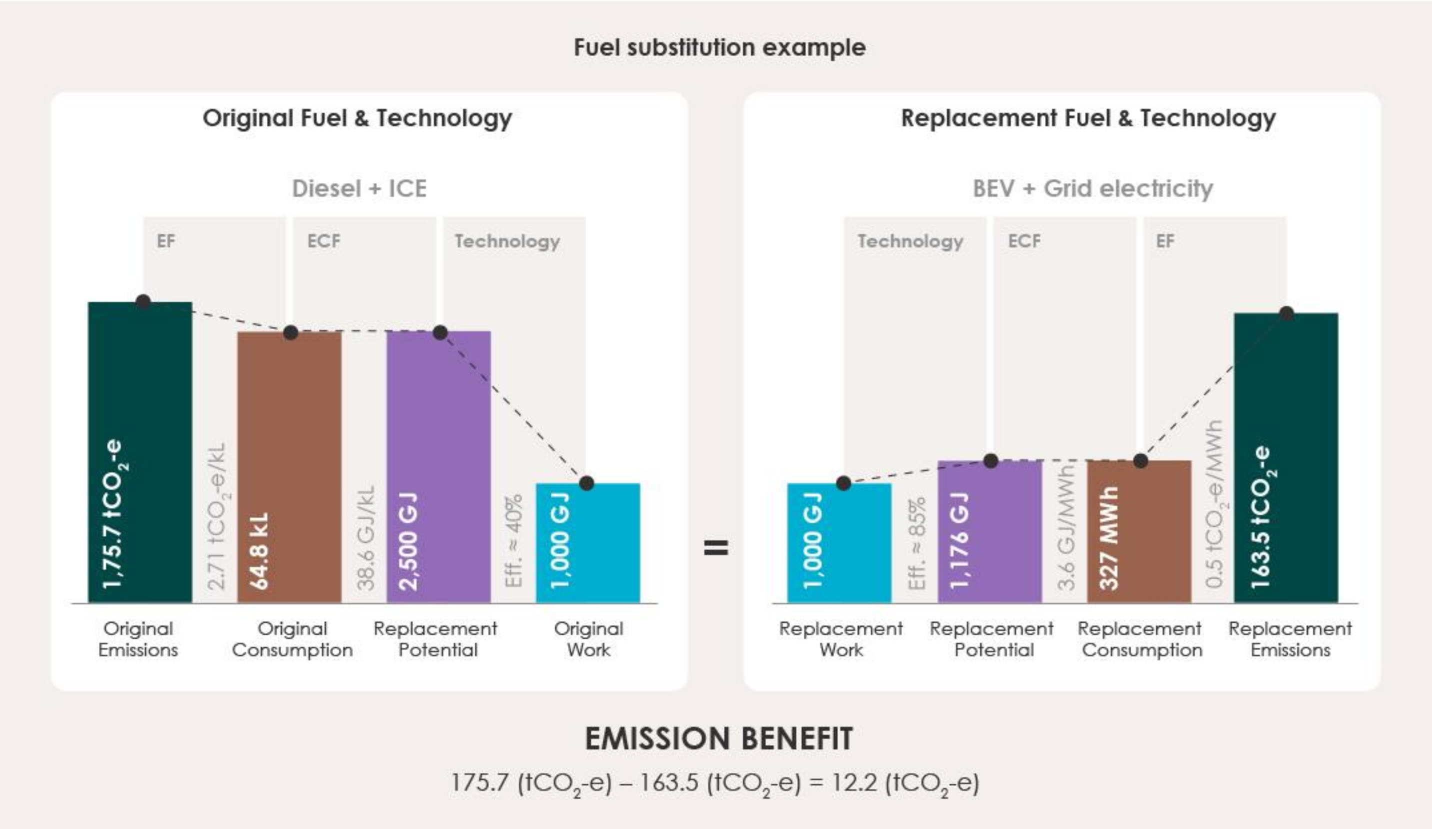


Figure 61: Emission benefit calculation visualised. This includes a grid factor of 0.5 tCO_2-e/MWh for simplicity

Appendix B: Decarbonisation score methodology

In the three Mining in a the Low-emissions economy reports, decarbonisation' scores are used to guide technology assessments.

Description and purpose

We have developed decarbonisation scores as a comparative analysis of stationary energy and material movement technologies, scoring each based on a range of social, technical, market, regulatory and economic factors. These scores provide a reference point for decision makers, in advance of site-specific planning and assessment.

The purpose of these scores is to provide an overall and general view of each technology in a comparative framework. Aiming to consolidate a range of factors into a single number, each technology and use case has a range of factors that indicate performance. The primary factor for decarbonisation is the relative emissions abatement of a technological substitution and is central to the decarbonisation score. This abatement is then modulated by a series of other factors as identified by each category for consideration in a table. Each of these categories may then be weighted differently depending on the use case. This culminates in a single number that embodies the decarbonisation impact weighted by other relevant factors.

Energy storage technologies do not have a direct emission abatement associated so a different approach is taken. The scores in these cases are the sum of relevant component factors.

Caution and caveat

The decarbonisation scores are developed in a specific context and should only be used to provide initial assessments. They are semi-qualitative assessments and ultimately imperfect. The scores aim to quantify qualitative and highly context-dependent information. Each context is different, and these decarbonisation scores should not substitute rigorous analysis.

Methodology

Technologies with emission abatement

For technologies that have associated abatement, such as haulage abatement, the decarbonisation score (D_s) is based on a weighted average using component factors (F)[42], weighted accordingly and proportional to emission benefit (E_B). These are weighted to prioritise the value of each component. Mathematically, these are represented by the sum of the component factors multiplied by an array of weightings (W):

$$D_s = E_B \sum_{i=0}^{n} \frac{\sum_{i=0}^{n} F_i W_i}{\sum_{i=0}^{n} W_i} \times 10$$

Both the emission benefit and the sum of component factors are between 0 and 1, so they are then multiplied by 10 to give a number between 0 and 10. Where the emission benefit is negative (the technology is worse than the base case), the decarbonisation score is negative. This is seen with onsite generation of hydrogen for FCEV without green power.

Technologies without emission abatement

Not all technologies relevant to decarbonisation have associated abatement. Batteries, for example, are a conduit for generation technologies to decarbonise energy consumption. Batteries are still important components of decarbonisation as they enable other technologies to achieve greater abatement. Thus, there is no emission benefit included:

$$D_s = \frac{\sum_{i=0}^{n} F_i W_i}{\sum_{i=0}^{n} W_i} \times 10$$

The weightings are not directly a number between 0 and 1 and must be normalised so the sum of all the weightings divides the product of the component factors and the weightings. These are then multiplied by 10 to give a number between 0 and 10, the decarbonisation score.

The weightings array is different for different use cases. In the case of batteries, the ability to respond quickly is less important for long-term storage, so the long-term services component factor is weighted as zero.

42 'Component factors' are the categories that make up each table, such as the TRL, CRI, Health & Safety Benefit, etc.

Weightings and component factors

The numbers that underly the decarbonisation score are the weightings and component factors. As discussed, the component factors are the numbers that are given to each factor such as TRL or CRI. The weightings are an array of numbers that multiply each component factor.

Each component factor is a number between 0 and 1 as it is a representation between its minimum and maximum score. For example, in the case of TRL, there are 9 levels. Each of these levels is given a score of 1 through 9, with 9 being TRL 9 and the most mature. The maximum score is 9, and each score is divided by 9 to give a component factor.

$$F_i = \frac{S_i}{max(S)}$$

In the case of TRL and CRI, these are linear. Each score is +1 on the previous score and increases linearly. The way that this component factor system is set up is that this does not have to be linear. For the long-term storage factor, there are four possible scores:

– Inter-seasonal storage, S = 10.

– Intra-seasonal storage, S = 7.

– Day-to-day arbitrage, S = 1.

– No long-term storage, S = 0.

If these scores were linear, they would increase by 2.5 each category. They are non-linear because the step-up in difficulty is arguably non-linear.

Each of these scores that build up into the component factors and the weightings that are applied to these numbers were developed with in-house expertise within ENGIE Impact. The weightings of each represent ENGIE Impact's experience.

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