

Optimal hybrid microgrid sizing framework for the mining industry with three case studies from Australia

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Abstract

The mining industry is showing increasing interest in adding renewable energy sources (RES) to their mines energy mix as one of the principles of sustainable and profitable mining. This paper proposes a systematic and integrative optimal economic hybrid microgrid sizing framework for profitability analysis in off-grid hybrid renewable-energy-based microgrids in the mining industry. The proposed framework is validated with three case studies in different mining locations in Australia based on real market data, investigating various mining site power configurations, and considering the key technical, environmental, and economic considerations. The results highlight the impact of integrating RES in greenfield or brownfield mines in terms of diesel/RES assets sizing and total cost of electricity generation for each scenario, in addition to evaluating the feasibility of grid-extension to the mining site versus on-site generation for a greenfield scenario. Sensitivity analysis is carried out to study the impact of varying different input parameters on the system size and cost. The contributions of this research thus provide practical insights on the profitability of hybrid microgrids in mining applications to the various stakeholders such as independent power producers (IPPs), mining facility owners and policy makers.

1 | INTRODUCTION

Global investment in renewable energy capacity excluding large hydro-electric projects was \$272.9 billion in 2018, 12% less compared to 2017 due to capital cost declines in various clean energy technologies such as, solar photovoltaics (PV) (−75% since 2010), onshore wind (−20%) and battery storage (−50%). However, after adjusting for cost declines to 2018 cost levels, renewables investment is up by 55% since 2010. Solar PV technology attracted the most capacity investment globally (\$133.5 billion), although this was down 22% compared to 2017, while wind secured \$129.7 billion, up 3% [1]. This shift helped renewables, excluding large hydro, to represent nearly 68% of the net new generating capacity added in 2018 worldwide, thus boosting its global electricity share from 11.6% in 2017 to 12.9% in 2018 and to avoid an estimated 2 Giga-tonnes of greenhouse-gas (GHG) emissions [2].

The mining industry is an energy intensive industry that depends mainly on fossil fuels, both in the initial development stage and throughout the life of a mine. The energy costs

accounts for up to 30% of a mine's operation expenses [3]. The energy consumption in mining industry accounts for 38% of total industrial energy use and 11% of the global energy consumption. Accordingly, without new policy measures, this energy consumption is expected to double by 2050 [4]. Adding to that, with rising mineral demand and falling ore grades, mining energy demand is estimated to increase by 36% by 2035 [5]. As a result, the mining industry is currently responsible for 4–7% of GHG emissions globally [6]. Many mines are located in remote locations far from the power grid, these mines transport diesel fuel over long distances to feed on-site generators which is expensive and makes their operation cost heavily affected by diesel price volatility. The mining industry currently faces pressure from governments, investors, and society to reduce its GHG emissions. Therefore, many mining companies are making progress towards decarbonisation, most of the top 40 mining companies targeted a reduction in their GHG emissions between 3% and 5% by 2020 [7].

There are many strategies that can advance this goal including, cleaning up the energy supply mix by adding renewables

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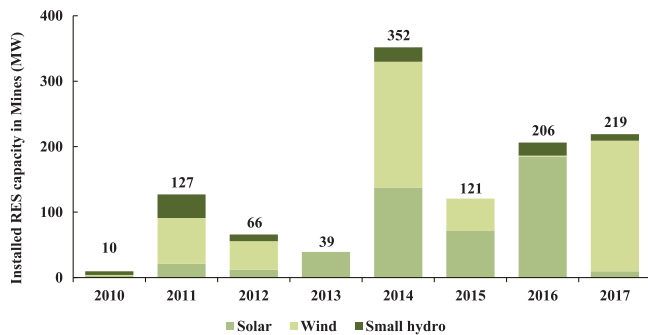


FIGURE 1 Global renewable energy installed capacity in mining projects by different technologies [8]

(attracted by falling costs, proven reliability and being environment friendly) to the mine's energy mix, Figure 1 shows the global renewable energy installed capacity in mining projects classified by technology [8]. Electrifying and automating equipment and processes that run on fossil fuel and improving mining processes efficiency by integrating energy management as a corporate initiative is also a considered solution [9]. Ref [10] highlighted that by integrating a solar PV power into a hybrid mining power plant can achieve average cost savings in the range of 25–30%, and in case of very isolated locations with higher diesel prices, the savings can amount to more than 70%. As a result, renewable energy in mining has achieved a new record in 2019, with over 4.5 GW of project announcements, over four times the previous record of around 900 MW in 2018 [11].

1.1 | Power generation sourcing arrangements in mining applications

Many mining companies do not usually own the renewables generation assets because a power plant is a low-return asset: 6–10%, compared to the mining return of 50% or more). Thus, most mining companies have shown themselves to be open to outsourcing power generation activities to third-party providers called independent power producers (IPPs). IPPs sell electricity to miners on a power purchase agreement (PPA) basis. A PPA, which has a popular way of achieving cost savings while integrating renewables, is a performance-based contract that creates a “fair” and risk controlled agreement for the purchase and sale of energy between a buyer (the miner) and provider (an IPP) for a long-term period (contract period). A typical PPA length for renewables depends on the mining site lifetime, with 20 years being the most common term and PPAs are strongly correlated with off-grid locations of the mines [12]. A PPA has several parameters to define, including the contractual length, point of power delivery, practicable price, minimum and maximum energy deliveries, penalties, insurance, milestones and defaults, the interconnection with the grid, government involvement in the project, and many others variables.

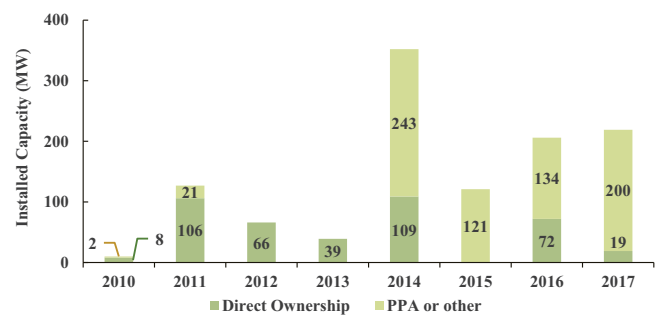


FIGURE 2 Global renewable energy installed capacity in mining sector by different sourcing arrangements [8]

PPAs use levelised cost of electricity (LCOE) models (which determine, the payback period of the installed assets capital costs and the project profitability) to determine a fair price of energy. Therefore, for a project to be financially feasible for an IPP, the nominal PPA price must be higher than the LCOE to obtain a reasonable profit depending on a specified (target) internal rate of return (IRR). Therefore, the negotiation of the LCOE and PPA terms is iterated until both parties (miner and IPP) are satisfied [13–16]. The volume of corporate PPAs (CPPAs) has increased immensely as the market data illustrate how global CPPAs have reached 46.4 GW of installed power in 2019 in various energy application sectors (renewable PPAs has almost doubled in just the past 2 years) [17, 18], including mining sector, Figure 2 shows the installed renewables capacity in mining sector until 2017, classified by sourcing arrangements into: self-generation and PPAs, illustrating the increased popularity of PPAs in the mining sector.

PPAs can have different structures such as fixed-price, fixed-escalator (typically 2–3%/year), or more customised structures, such as the first 10 years of the term being fixed and then an escalating price comes into effect after year 10. In mining sector, the expected mine life becomes a key determinant (as it will determine the PPA length that the mining company can commit to) on whether renewable projects are competitive or not from miners' perspective. A longer mine life enables more hybrid power generation options to be economically viable. However, with a shorter mine life, the attractiveness of renewable energy solutions for off-grid mines falls. Adding to the mine life, the timing of the PPA contract decision (a greenfield (new) project or a brownfield (existing) project) has a significant impact on the economic viability of employing hybrid power generation [19]. However, installing renewables can be about more than powering the mine, it can be used as a powerful argument in community negotiation before building new mining facilities, as it makes the site itself cleaner and quieter and it can continue to power the community long after the mine life to contribute to the community sustainability.

1.2 | Contributions and scope

To the best of the authors' knowledge, a detailed economic and technical investigation of the power generation alterna-

tives for the mining industry with practical case studies has not been thoroughly considered in the literature. This paper consequently takes the following points into consideration within the presented model: impact of the project life time and the PPA length, the project salvage value, the renewables energy share percentage, the environmental parameters variation (e.g. solar irradiance), the discount rate, the availability of public RES grants, and the impact of renewable technologies cost reduction on the profitability study. In addition, this paper also considers the impact of the mine life status (greenfield or brownfield) on the hybrid power system profitability by providing a high-level assessment in some case studies. Furthermore, sensitivity analysis has been conducted to evaluate the effect of varying the main system parameters (technical and economic) on the system cost of electricity (COE), as well as the breakeven distance for the case of grid extension assessment.

In this work, an optimal hybrid microgrid sizing framework for mines is developed to investigate the profitability of integrating different renewable energy and energy storage technologies for the energy mix of an existing or a new mine. The framework is tested on three case studies in Australia, which has intensive mining activities, using real market data and cost indicators. Intuitively, the combination of installed RES, storage and diesel capacities at the mining site has a direct impact on the project profitability. The considered case studies cover the following categories: (a) an existing mine operated by diesel generation (brownfield), with a planned expansion by installing RES plus storage assets to cut the diesel operating costs, (b) a new mine (greenfield) where the additional degree of freedom of co-designing diesel, RES and storage (hybrid) assets should add more flexibility to the design optimisation, (c) a new mine (greenfield) where the hybrid design option is compared to expanding the utility grid to the mining site. The locations of these three projects are also scattered across Australia to showcase the impact of environmental parameters variations. Each case study has a different focus in order to cover a wide range of possible scenarios and provide the reader with expanded insights on the industry.

The remaining of this paper is arranged as follows: Section 2 presents an overview of the available energy assets optimal sizing techniques. Section 3 presents the proposed optimal hybrid microgrid sizing framework for mining applications, Section 4 then summarises the Australian mining market status and presents three case studies from Australia with simulation results to test and discuss the various aspects of the proposed framework application. Finally, the work done is concluded in Section 5.

2 | OPTIMAL SIZING TECHNIQUES FOR MINING ENERGY ASSETS

To utilise the available renewable energy resources efficiently and economically, optimal models are required to be developed. However, optimal modelling of a hybrid power generation system is a very complex task (since it depends on the knowledge of energy sources, technical specifications, metrological data, and

load profiles) which requires the development of mathematical models for each component as first step. Then these mathematical models need to be optimised through various optimisation techniques based on a variety of objective functions (a single objective optimisation (SOO) function or multi-objective optimisation (MOO) functions) including technical, economic, environmental and social criteria in order to come up with effective solution (or a set of trade-off solutions, which allow decision makers to select the most suitable solution based on the problem requirements) that provides optimal system size and a reliable supply with least cost [20, 21]. The hybrid power generation system optimal sizing methodologies can be categorised as classical (utilise differential calculus in deriving the optimum solution) algorithms, modern (utilise artificial intelligence (AI) methods to determine the global optimum system with better convergence and accuracy) techniques and computer software tools (such as: hybrid optimisation model for electric renewables (HOMER), improved hybrid optimisation by genetic algorithm (iHOGA), RETScreen, Hybrid2 (hybrid power system simulation model) etc.) [22]. Ref [23] presents a comprehensive review of 31 computer tools, among software tools, HOMER Pro is found to be the most largely used economic optimisation tool and has been extensively validated by several researchers for optimal sizing and economic analysis of hybrid renewable systems. HOMER Pro software is used to design and evaluate technically and financially the various options for off-grid and on-grid power systems for remote, stand-alone and distributed generation applications. HOMER Pro has a friendly user interface, access to international metrological databases, a rich combination of renewable energy systems with updated component technical specifications from different manufactures, comprehensible programming features and sensitivity analysis for model variables, which makes it easier and faster to evaluate many possible hybrid system configurations by sorting out the various design options by means of the net present cost (NPC) [24]. Although, HOMER Pro is a highly capable techno-economic sizing tool hybrid power system, it lacks the capability to perform a deep technical performance investigation, which requires stability and transient analysis, capture of voltage and frequency variations and reactive power production etc. due to the lack of an AC optimal power flow analysis [25].

HOMER Pro has been used in various techno-economic analysis and sensitivity analysis studies [26–50] for different stand-alone or grid-connected hybrid microgrids (with different microgrid configurations from conventional to totally renewable with different configurable generation resources within the software (diesel generator, natural gas generator, solar PV, wind, biomass, fuel cell, hydro) energy storage devices including different battery technologies, hydrogen and supercapacitors) for different applications (residential, community, commercial and agricultural). These case studies covered systems in various countries such as: Canada [26, 36], Australia [27, 37], India [28, 32, 40, 44], Spain [29], Morocco [30], Malaysia [31], Greece [33], Venezuela [34], Saudi Arabia [35], Iraq [38], Myanmar [39], Sudan [41], South Africa [42, 49, 50], USA [43], Egypt [45], China [46], Iran [47] and Pakistan [48]. Two stud-

ies [29, 48] integrate demand side management to minimise the unnecessary capital initial investment in the power plant. Two studies [49, 50] compare between the local hybrid generation and the grid extension option. All the above studies consider 25 years as standard life time for the hybrid power system. Sensitivity analysis includes some technical specifications (such as wind speed, PV tilt angle) and economic (diesel fuel price, battery price, and inflation rate). Based on the proven capabilities of HOMER Pro software, it is selected to perform the hybrid power plant optimisations in this work for mining application.

2.1 | Objective function of optimal configuration

In this paper, the total NPC as the financial figure of merit to assess and compare the feasibility the various studied scenarios. NPC accounts for installation, maintenance, operation and replacement costs and buying electricity from the grid and all revenues (include salvage value and grid sales) that occur over the entire planning time horizon into a lump sum in a present monetary value, in which future cash flows are discounted to reflect their current values using the project discount rate of the hybrid power system [51–54].

As an economic optimisation tool, HOMER Pro has the following objective function to minimise the COE while maintaining the various system constraints [41, 44, 45], as:

$$ObiF = \min (NPC_{tot}) = \min (C_{ann, tot} / CRF (i_{real}, R_{Proj})), \quad (1)$$

where $ObiF$ is the objective function, NPC_{tot} is the total project net present cost (\$) (which is the summation of the NPC of each component in the project), $C_{ann, tot}$ is the total system annualised cost (\$/year) and CRF is the capital recovery factor (also, called discounting factor) which is calculated by:

$$CRF (i_{real}, R_{Proj}) = \frac{i_{real}(1 + i_{real})^{R_{Proj}}}{(1 + i_{real})^{R_{Proj}} - 1}, \quad (2)$$

where i_{real} is the real interest rate (%) and R_{Proj} is project's lifetime (year). For each component, the total NPC is the present value of all costs minus all the revenues during its lifetime. The project salvage value is the estimated value of the project components at the end of the project lifetime, the salvage value (\$) can be calculated as:

$$S = C_{rep} \cdot \left(\frac{R_{comp} - \left(R_{Proj} - R_{comp} \cdot INT \left(\frac{R_{Proj}}{R_{comp}} \right) \right)}{R_{comp}} \right), \quad (3)$$

where C_{rep} is the cost of component replacement (\$), R_{comp} is component's lifetime (year), and INT is a rounding function for converting an integer number to a real number.

The COE or LCOE is the average cost of electricity per kWh of useful electrical energy produced by the hybrid power system over its lifetime. The COE is an important criterion for determining the cost-effectiveness of a given system and is calculated as:

$$COE = \frac{C_{ann, tot}}{E_{served}}, \quad (4)$$

where E_{served} is the yearly served energy including the energy required to serve the primary and deferrable loads during a year, plus the amount of energy sold to the grid.

3 | PROPOSED OPTIMAL HYBRID MICROGRID SIZING FRAMEWORK FOR MINING INDUSTRY

This section contains a detailed description for the proposed optimal hybrid microgrid sizing framework, which can be considered as a systematic and integrative IPPs' decision-making tool for efficient profitability assessment of hybrid microgrids in mining applications. As indicated, this study used the HOMER Pro software for optimal design of hybrid microgrid systems and complements the conventional applications of the software by systematically undertaking pre and post HOMER Pro analyses as illustrated in Figure 3, where CAPEX refers to the investment capital cost, OPEX refers to the operating cost, NPV refers to the net present value, and FiT refers to the feed-in-tariff.

In the Pre-HOMER Pro analysis stage, a detailed quantitative assessment of the mine load profile, the mine life time, the mine's status (a greenfield or brownfield mine), the proposed PPA contract length, and the proposed hybrid mine energy mix (fossil generation, renewables generation and energy storage) are undertaken.

HOMER Pro proposes two default dispatch strategies (energy dispatch strategy that controls system operation and manages the flows of energy between different system components); load-following (LF) and cycle-charging (CC). Under the load-following strategy, generators produce enough power to meet the load requirement without charging the energy storage device. Alternatively, for the cycle-charging, after serving the load, the surplus energy is used to charge the energy storage device. The optimisation takes both dispatch techniques into consideration and utilises the one that satisfies the technical requirements with least cost. HOMER can also consider a combination of both dispatch techniques based on the current time-step optimisation. Moreover, flexible dispatch algorithms based on user needs can be programmed into HOMER through a dedicated MATLAB interface (not considered in this work).

In the covered case studies, a set of climatic, technical and economic, and incentive inputs are considered. Based on the mine location, resources such as temperature and solar irradiance are obtained. The considered technical constrains does not allow for mine power shortages (i.e. the generation has to constantly be able to follow the demand requirement). This is

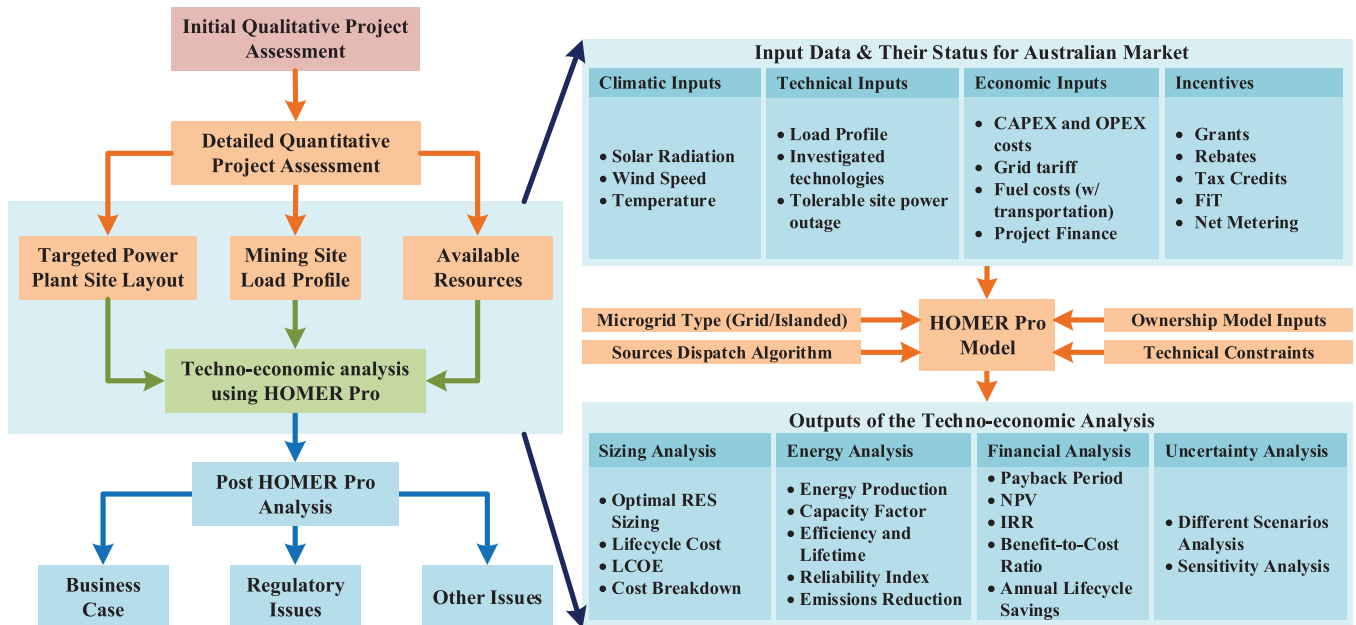


FIGURE 3 The proposed optimal hybrid microgrid sizing framework for mining applications layout

because a tolerable outage reduces the generation assets site at the expense of reliability, which is a main requirement in mining applications. The considered RES in these case studies is PV combined with storage, whereas the presented methodology can similarly be applied with different combinations of RES assets. Diesel power plants are considered in each case study to complement the RES operation for increased reliability. Incentives such as government-supported grants are also considered as a key input since they impact the overall project cost and consequently impact the profitable assets sizing combination. Finally, the business-related dimensions are performed from the concerned stakeholder point of view at the Post-HOMER Pro stage.

4 | OPTIMAL SIZING FRAMEWORK CASE STUDIES: AUSTRALIAN MARKET

Australia has one of the world's highest per capita emission of GHGs due to its high dependence on coal-fired power stations, in addition to that, Australia provides close to a third of world's coal trade. On the other hand, Australia has the highest average solar radiation per square metre of any continent in the world (global horizontal radiation (GHI) of 9.7 kWh/m²/day, in addition to some of the best wind energy resources in the world (7–8 m/s at 100 m) and widely distributed across the continent [55, 56].

The Australian off-grid remote community and mining electricity market share represents 2% and 6%, respectively. Most off-grid communities and mining sites in Australia currently rely on diesel fuel (currently there is over 1.2 GW of diesel generation capacity installed off-grid in Australia [57]), exposed to price volatility, high fuel transportation

cost over long distances and supply interruptions. The Australian off-grid market has an estimated potential of approximately A\$600 million with approximately 213 MW of renewable project opportunities in the short to medium term and expected long-term growth to over A\$2 billion of investment with 854 MW to one GW additional capacity market potential [58].

Energy consumption in the mining sector represents 11.9% of the Australian energy consumption in 2018 with a 10 years average annual growth of 7.9 [59, 60]. The number of operational mines in Australia is estimated around 400, 65% of these mines are grid-connected to primary electricity markets and half of the remaining off-grid mines rely on IPPs to supply their electricity. For miners (off-grid and on-grid), procuring a renewable source of power simply makes good business sense, improved supply security and reduced GHG emissions, therefore, Australia is taking a leading role in driving renewable energy developments for the mining sector as a result of increasing grid energy prices, high diesel plants operating costs and the RES and storage cost declination [61]. Since 2016, 58 renewable PPAs have been publicly confirmed, contracting 2.3 GW of renewable electricity and supporting 4.3 GW of project capacity [18].

4.1 | Australian renewable energy market funding support schemes

Federally, Australian Renewable Energy Agency (ARENA) and the Clean Energy Finance Corporation (CEFC) are the two major institutions driving the innovation in clean energy technologies. Both have identified wind and solar as priority areas for research and development investment. ARENA launched

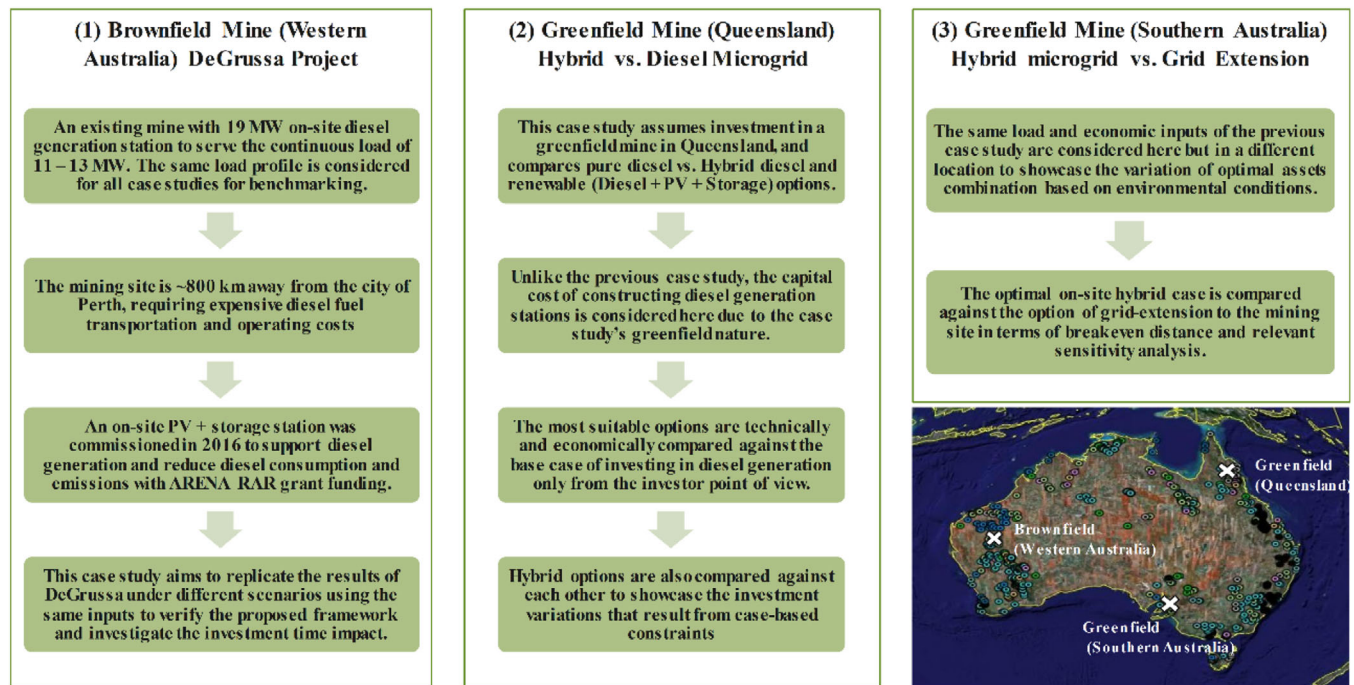


FIGURE 4 Case studies: Three Australian mines at different location with different specifications

the Regional Australia's Renewables (RAR) program in 2013, focusing on hybrid and integrated systems in off-grid and fringe-of-grid communities. ARENA received 72 applications for the RAR program, 18 of which were approved for funding and four projects have been discontinued. The 14 active projects in six states have a total value of \$323 million and collectively add 78.32 MW to off-grid renewable capacity, out of these 14 projects two are off-grid mines (Weipa and DeGrussa). ARENA provided A\$ 20.9 m to the A\$39.47 m total project cost as recoupable grants to a 10.6 MW solar project and 6 MW/1.8 MWh of energy storage at Sandfire resources' DeGrussa copper mine in started in July 2014 and commissioned in August 2016. Also, ARENA contributed A\$11.3 m to the A\$5.88 m total project cost to the 6.7 MW Weipa solar farm located at Rio Tinto's Weipa bauxite mine in Queensland in 2014 and the solar farm is fully operational in 2016 [62–64].

4.2 | Case studies: Background

To demonstrate the proposed framework for optimal hybrid microgrid sizing for mining applications, three case studies for off-grid mines are developed at different locations in Australia with high concentration of mining activities to assess different possible scenarios. These case studies cover different mine's status (a greenfield mine and a brownfield mine), investigation of a grid extension feasibility versus on-site generation, the impact of varying the natural resources, as illustrated in Figure 4. The coloured dots on the Australian map in this figure represent mining locations. The objective of covering different case stud-

ies is to provide the reader with a summary on the complex process involved in a hybrid plant sizing exercise based on the current mine state and location. The first case study aims to replicate the design of an existing hybrid power plant in DeGrussa mine in order to validate the methodology, followed by two greenfield case studies.

4.3 | Case study 1: DeGrussa project

DeGrussa copper-gold mine, located ~800 km north of Perth, Western Australia, is a world leading mine in solar-diesel-battery system installations, and has one of the largest integrated off-grid solar and battery storage facilities in Australia. The PV plus battery system is integrated to an existing 19 MW diesel-fired power station to cover the mine load profile—consistently (24/7) between 11 MW and 13 MW. This ARENA funded hybrid project extension was commissioned in 2016. It comprises of a 10.6 MW solar array utilising 34,080 solar panels over 20 hectares. It uses single-axis tracking technology, combined with 6 MW/1.8 MWh of short term lithium-ion battery storage to compensate for the slower diesel generation ramp-rate. The project aimed to reduce the annual diesel consumption by around 5 million litres a year from 25 million, and cut the carbon emissions by more than 12,000 tonnes of CO₂ annually. In fiscal 2018 the solar farm, which has a 6-year PPA with Sandfire, produced 17% of the mine's power against a target of 21% [65].

HOMER pro has been used to model the DeGrussa off-grid hybrid microgrid, using the economic and financial parameters listed in Table 1. The project lifetime was set to six years

TABLE 1 Economic and financial parameters for hybrid PV–battery system at Australia [8, 19, 66, 67]

System Component/Parameter	Value
PV system (inc. inverter)/kW in 2016	3350 A\$
PV O&M/kW/year	30 A\$
Battery/kWh in 2016	860 A\$
Bidirectional battery converter/kW	300 A\$
Battery O&M/kW/year	10 A\$
Diesel plant capital cost/kW	0, brownfield
Diesel fuel price/litre	1.264 A\$
Diesel plant O&M/hour	570 A\$
Nominal discount rate	6.5%
Inflation rate	2%
Real discount rate	4.41%

TABLE 2 HOMER Pro developed model for DeGrussa project in relative to the real project

	DeGrussa	HOMER Pro Model	Difference (%)
Required investment (M A\$)	39.47	38.3	3%
Fuel saving (million litres (ML)/year)	5	5.006	0.1%
CO ₂ emission (tonnes/year)	12,000	13,094	9.1%
RES fraction (%)	21	21.6	2.9%

to match the PPA contract period. The developed HOMER Pro model accurately reproduced the real project results as illustrated in Table 2. Figure 5 illustrates the contribution of each component of the hybrid power plant to meet the continuous load profile of the mine over a week window of September, the short term battery usage is utilised to compensate for the PV output fluctuations. The cash flow breakdown, shown in Figure 6, illustrates the significant fuel portion of the annual operating expenses as 20 million litres are still needed each year for operation of the 19 MW diesel generators, which resembles the real mine operation scenario. The

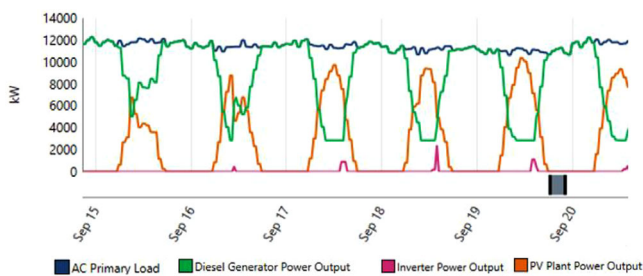


FIGURE 5 DeGrussa’s hybrid (PV, battery and diesel) power plant to satisfy the mine continuous load profile over a week window in September, HOMER Pro model

salvage value at the end of year 6 represents the PV and storage assets value, taking their average lifetime and depreciation into account.

In order to investigate the impact of the RAR ARENA grant and the falling cost of solar PV and battery technologies since the project has been commissioned in 2016, the profitability analysis covered the following scenarios, maintaining the same component sizes of the hybrid power plant:

- 2015–2016 prices (project construction/commission time-frame): without and with ARENA grant.
- 2019–2020 prices (today’s prices): without and with ARENA grant.

The 2019–2020 PV (/kW) and battery (/kWh) system cost decreased by 41% and 50% compared to 2015–2016 prices, respectively [19, 66]. Results are presented in Figure 7, where AUD and A\$ are used interchangeably hereafter. The figure indicates that the investment in 2015–2016 would be at the edge of profitability without the RAR ARENA grant. Figure 7(a) illustrated the simulated investment outcomes at the end of year 6 in terms of IRR, whereas Figure 7(b) illustrates that in net present value (NPV). The project NPV is negative (no profit) without ARENA support in 2016 and the overall site COE is $COE_{2016} = 0.352$ A\$/kWh (see Figure 8), which is almost equal to that of the diesel base case, as $COE_{diesel} = 0.351$ A\$/kWh, where the COE is calculated as in Equation (4). The ARENA grant adjusted the IRR to around 31% ($>$ $>$ real discount rate = 4.41%) at a comfortable profitability margin as compared to the base full diesel operation case.

On the other hand, if the investment for a similar PV + Battery capacity took place in 2019–2020 with lower investment cost and without ARENA grant, the COE will be 9% lower than the 2016 diesel base case. Receiving the same level of RAR ARENA grant in 2019–2020 for a similar project skyrockets the IRR, and the COE will be almost 25% lower than the 2016 diesel base case (see Figure 8). This illustration showcases the significant impact of the falling renewable technologies cost on the hybrid power systems profitability, which can make it an attractive investment to miners even without substantial government subsidies.

Having said that, it is essential to note that the hybrid power plant salvage value is taken into account for the presented profitability analysis, especially considering the relatively short announced lifetime of the DeGrussa project. That is, the existence of a ‘second-hand RES redeployment market’ is vital to capture the remaining value of these assets, especially in cases where the off-grid power plant is far from the nearest community and cannot be used for other applications after the mine shuts down. The Australian market already has dedicated companies for RES redeployment activities, which justifies the followed assumption [19]. HOMER Pro calculates the salvage value as a linear degradation function with respect to the asset lifetime and CAPEX.

Furthermore, an IPP which only provides the on-site RES should be interested in the RES COE instead of owning both diesel and RES/DER assets which is calculated for each

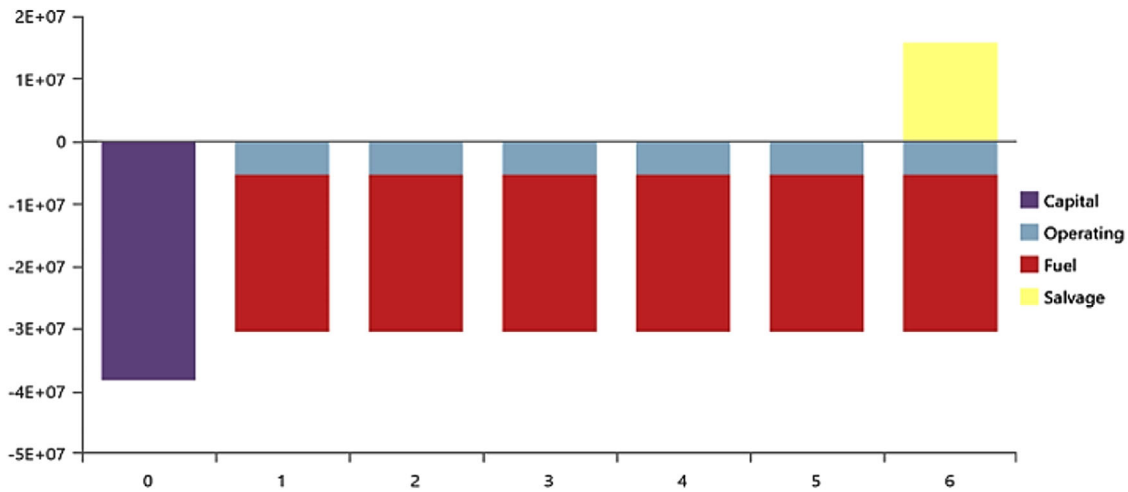


FIGURE 6 Simple cash flow of the DeGrussa project from HOMER Pro with a lifetime of 6 years (in A\$)

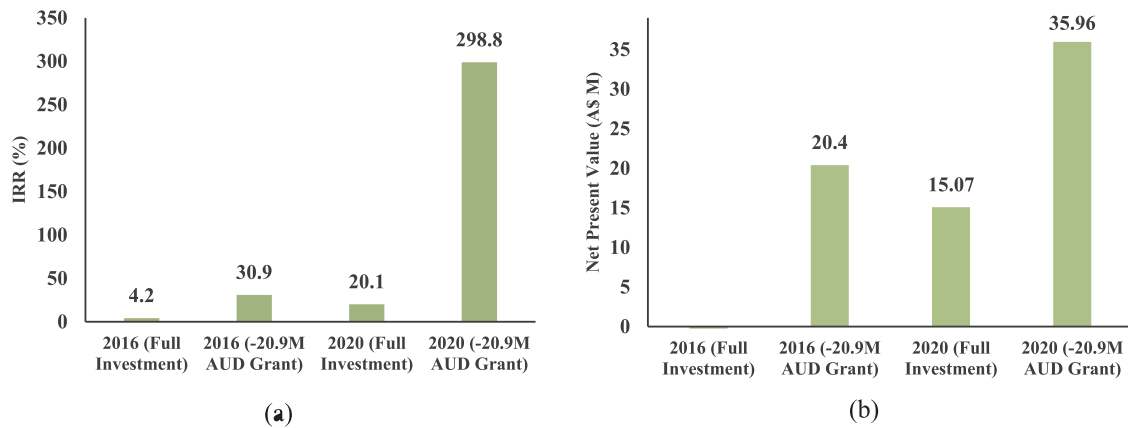


FIGURE 7 DeGrussa project profitability analysis economic indicators: (a) internal rate of return, (b) net present value

scenario for comparison as illustrated in Figure 8. That is, the system COE represents the total cost of electricity generation, combining both diesel and RES. Though, an IPP investing in a brownfield mine is likely to only invest in RES sources. The knowledge of these different costs can provide a quick tool for the profitability margin assessment by the IPP. A remarkable observation in Figure 8 is that the same level of ARENA support for the project at today's technology cost is likely to fully cover the required PV + storage cost to the extent that the cost of energy generated from the RES/DER combination could become negative.

The present case study has thus far considered the announced PV and storage sizes by DeGrussa to evaluate the high-level project profitability under different scenarios. Next, the optimisation capability of HOMER Pro is used to optimise the PV plus battery system size for the DeGrussa project based on the 2015–2016 and the 2019–2020 prices. HOMER Pro optimiser recommended around 10.6 MW PV and 1.8 MWh battery sizes for 2015–2016 prices case with ARENA fund, which nearly correspond to the actual implemented capacities, indicating a near

optimal output for the initial investment. On the other hand, the optimiser recommended 26.5 MW PV and 6 MWh battery for 2019–2020 prices case. As the renewable technologies prices falls, the renewable factor (RF) increases, the RF is defined to identify the quantity of power generated from the diesel generators compared to the amount generated from renewable resources, as:

$$RF\% = \left(1 - \frac{\sum P_{diesel}}{\sum P_{RES}}\right) \times 100 \quad (5)$$

The RF% is shown in Figure 9 for 2016 and 2020 costs. Also, hybrid system and renewable COE decreases, which improves the business case of integrating renewables in mining applications at larger capacities.

Finally, HOMER Pro sensitivity analysis has been used to investigate $\pm 50\%$ variation in some system parameters, as illustrated in Figure 10 for the DeGrussa project (low case: -50% , high case: $+50\%$). The effect of diesel price variation by 50% on the system COE is the most notable due to the annual con-

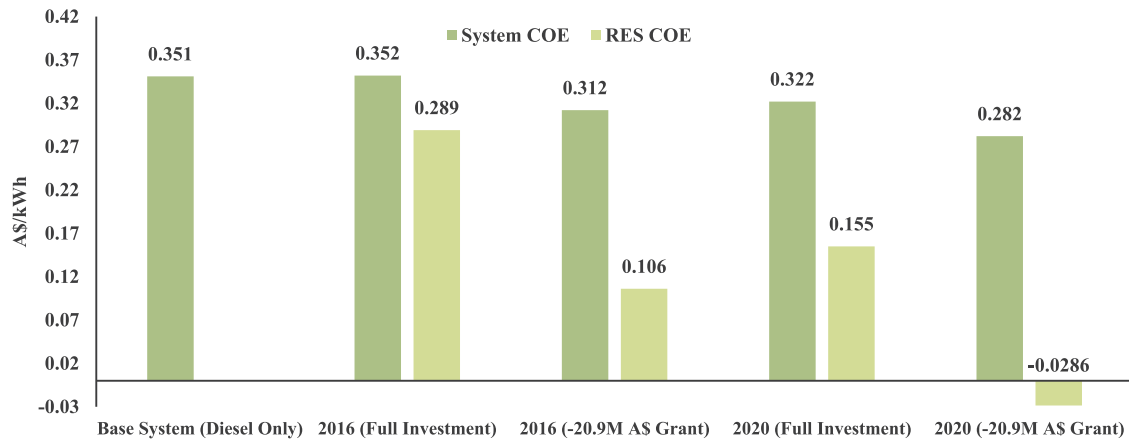


FIGURE 8 DeGrussa project cost of electricity in various scenarios

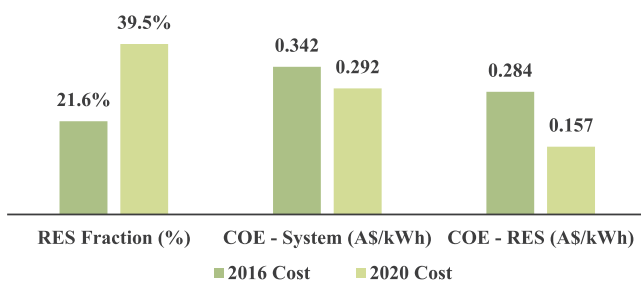


FIGURE 9 HOMER Pro Optimiser results for the DeGrussa project components size parameters using 2015–16 and 2019–20 investment costs (2020 RES/DER size: 26.5 MW for PV, and 6 MWh for battery)

sumption of 20 million litres even with the RES, followed by the PV investment cost. The sensitivity output is thus highly dependent on the project assets composition, since the battery, discount rate, PV cost and solar irradiance had miniature impact on the COE as compared to the diesel price for the DeGrussa project composition.

4.4 | Case study 2: Greenfield mine (Queensland)

The main advantage of investing in a greenfield mine’s power station is that the investor (e.g. IPP) has the flexibility of concurrently sizing the different hybrid generation assets optimally (Diesel, PV, Battery ... etc.) compared to adding a PV plus Battery system to an already existing diesel generation station as in brownfield mine case.

This case study independently considers three different configurations: (a) diesel generators (base case), (b) hybrid system with diesel generators and a PV system, and (c) hybrid system with diesel generation, PV and battery at a greenfield mine at Queensland, Australia. The project lifetime has been assumed to be 6 years with 2019–2020 components costs and continuous 11–13 MW load profile, similar to case study 1 in DeGrussa for easier benchmark. The environmental param-

eters were updated to reflect Queensland solar irradiance and temperature.

In this case study, six diesel generators (each rated at 2.8 MW at a CAPEX of 852 A\$/kW to provide a total capacity of 16.8 MW which guarantees 25% reserve capacity above 13 MW), are used as the base case. All the hybrid systems options are economically evaluated against this base case in terms of IRR, Payback Period ... etc. The HOMER Pro optimiser is used to determine the most economic sizing of each system component to optimally meet the technical and economic constraints of the site. In Figure 11, the diesel plus PV case resulted in a decrease in required diesel CAPEX capacity compared to the base case by 2.8 MW (i.e. offsetting a generator investment). The optimal added PV of 13.8 MW results in an excess, curtailed, PV output of 2.3% annually since the peak PV capacity is greater than the load demand. When storage is added, the optimal PV size is allowed to increase since excess generation can be stored. The most economic case here is composed of a 28.53 MW of PV, 11.25 MW/ 47.67 MWh of storage capacity and 14 MW diesel. Despite the large storage availability, part of the PV output is still curtailed at peak times with this configuration (2.7% excess energy). As a result, an additional case is considered (although slightly less economically viable) where the optimisation is constrained to 0% energy curtailment (in case a regulation exists in the target location), which results in slightly increasing the storage capacity to store the excess energy, while reducing the PV size as illustrated in Figure 11, at the cost of reduced overall PV contribution and increased fuel consumption (see Figure 13). Such scenarios emphasise again the importance of design trade-offs and site-specific considerations and/or regulations with regards to energy curtailment.

Although the base case has the lowest capital expenditures (CAPEX), it has by far the highest operational expenses (OPEX) mainly due to its high fuel consumption, as illustrated in Figure 12. The CAPEX increases consistently with diesel plus PV, hybrid without excess and hybrid with 2.7% PV curtailed energy, respectively. An opposite behaviour is observed with the OPEX for these cases because, although the same diesel generation capacity of 14 MW exists in all systems but the base case,

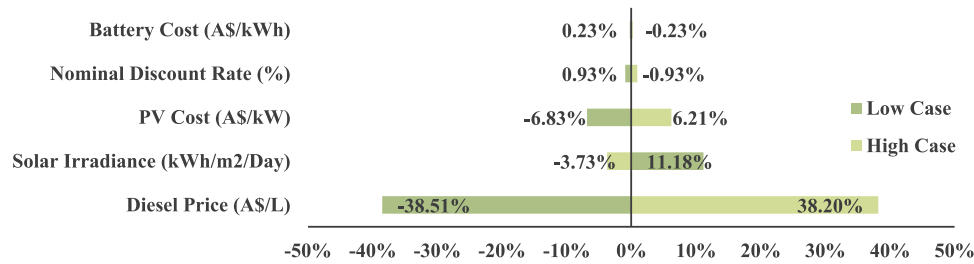


FIGURE 10 DeGrussa project HOMER Pro sensitivity results on COE following ±50% variation of each parameter

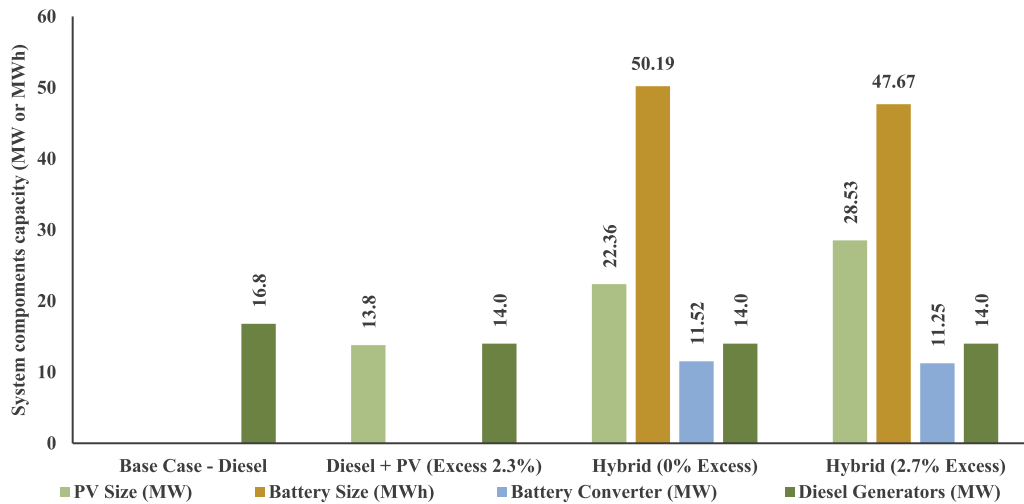


FIGURE 11 Optimal components size in various hybridisation options of case study 2

the use of diesel is significantly impacted by the existence of large hybrid systems, thus impacting the operating cost. This is also visible in terms of CO₂ emissions reduction as a result of this diesel offset as presented in Figure 13.

On the other hand, the profitability assessment presented in Figure 14 reveals the NPV, IRR and payback period for each case, in addition to the COE, and compares them to those of DeGrussa project under the 2020 investment cost assumption (without ARENA support). The system with most fuel saving

and CO₂ emissions reduction is also the system with the least COE. That being said, the high investment CAPEX cost associated to this system (hybrid with 2.7% excess energy) is a significant point to consider, given its impact on the IRR as compared to the diesel plus PV option. This calls for a trade-off assessment by the concerned stakeholder in order to balance the available CAPEX and the project lifetime OPEX against the absolute and relative profitability targets. Collectively, greenfield mine provides more flexibility in optimising the individual com-

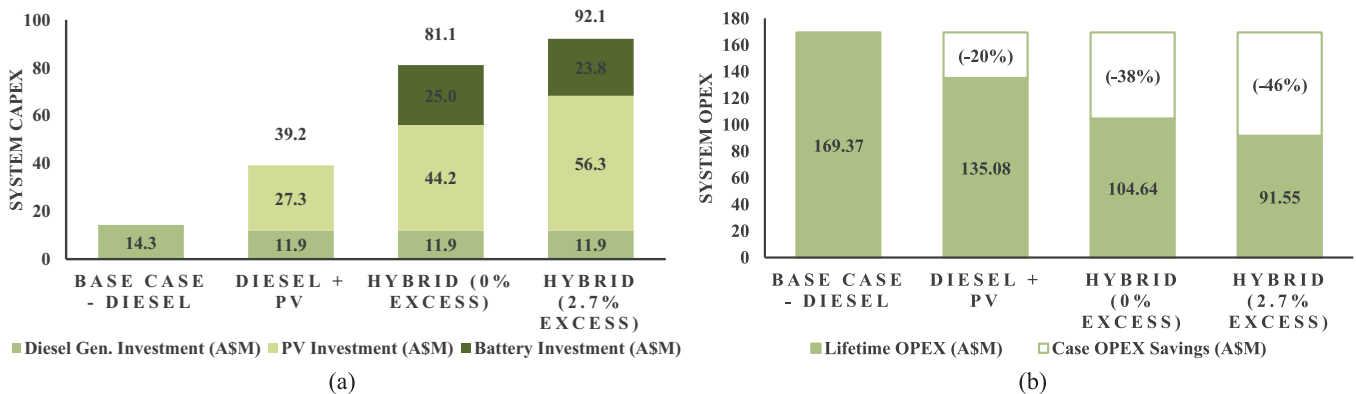


FIGURE 12 (a) CAPEX, (b) OPEX for the different scenarios in case study 2

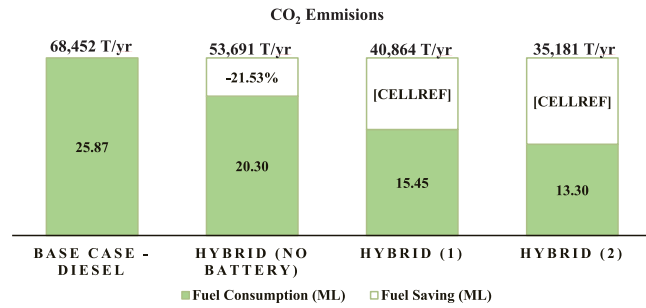


FIGURE 13 Environmental benefits and fuel reduction of different hybrid systems compared to the base case (where Hybrid 1: 0% curtailed PV generation, and Hybrid 2: 2.7% curtailed PV generation)

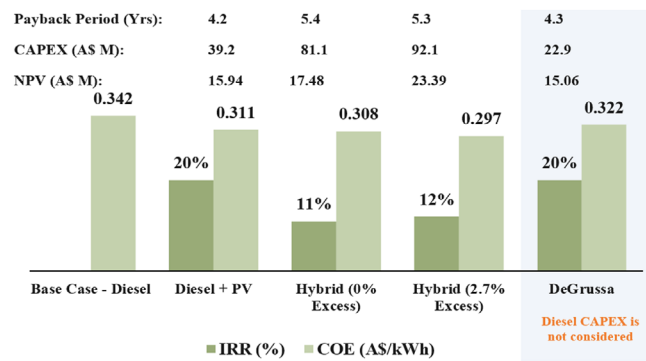


FIGURE 14 Profitability assessment of the different case study 2 systems

ponents of hybrid power plant to serve the economic and/or environmental objective of the project. As a result of greenfield mine design flexibility and higher average solar irradiance of Queensland compared to Western Australia (DeGrussa—case study 1), the Queensland case study results in a lower COE.

4.5 | Case study 3: Greenfield mine with grid extension assessment (South Australia)

The same load requirement and economic inputs of the previous case studies are considered here but in a different location (South Australia) to showcase the variation of optimal assets combination based on the available natural resources (mainly the solar irradiance) which is less than the Queensland case. Figure 15 illustrates the system schematic in HOMER Pro for this case study, which is the same as the one from case study 2.

The optimisation in HOMER Pro for a hybrid greenfield diesel, PV plus storage system in South Australia favoured less PV capacity as compared to Queensland at 14 MW, which led to offsetting most of the battery capacity from the previous case since a 14 MW system produces slightly higher output than the pseudo-constant 11–13 MW load demand (see Figure 16(a)). The excess electricity generated by the PV system in this case is curtailed as a more economically viable alternative by the optimiser. In order to illustrate the variation between case studies 2 and 3, Figure 16(b) shows the cost of electricity in the selected Southern Australian location if the same opti-

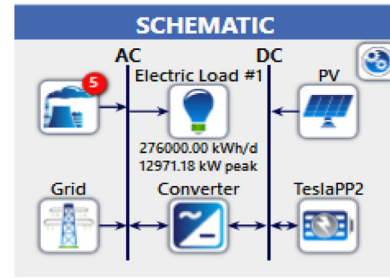


FIGURE 15 HOMER Pro schematic model for the Greenfield mine with grid extension case study

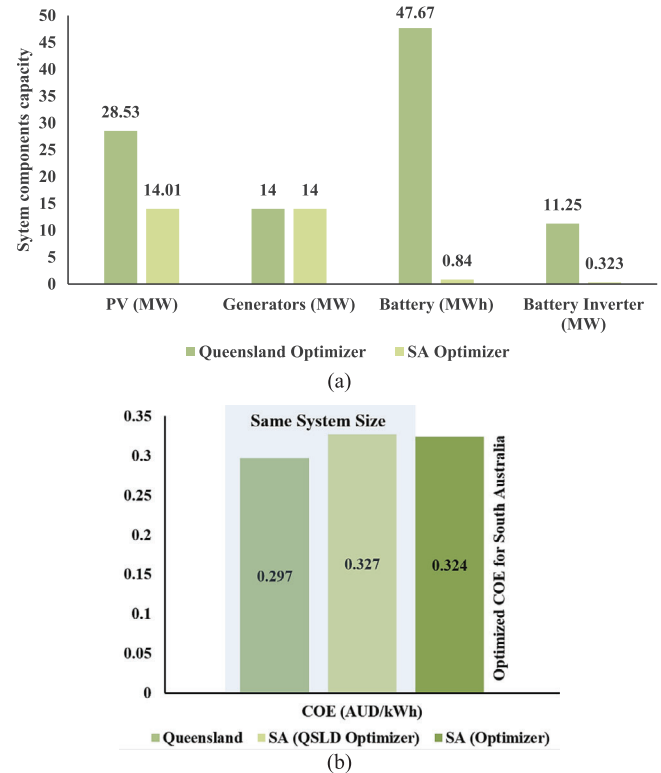


FIGURE 16 Sizing optimisation and cost of electricity for case study 3 compared to case study 2. (a) Queensland versus SA Optimiser results, (b) effect of system re-sizing on COE

mal combination from case study 2 is maintained (hybrid with 2.7% excess option), as compared to the optimisation results in Southern Australia. The COE from Queensland (case study 2) is shown for comparison. The small difference between both systems (0.324 A\$/kWh versus 0.327 A\$/kWh) illustrates again the importance of evaluating these options in terms of both absolute and relative profitability as discussed earlier.

For this case study, an additional key objective is to perform comparative analysis between grid extension and on-site hybrid microgrid using the optimised system in Figure 16. Three additional economic parameters are required, grid extension CAPEX (A\$/km), OPEX (A\$/km/year) and the grid electricity tariff (A\$/kWh) which is the cost of purchasing electricity from the grid to supply the mine load requirements. With

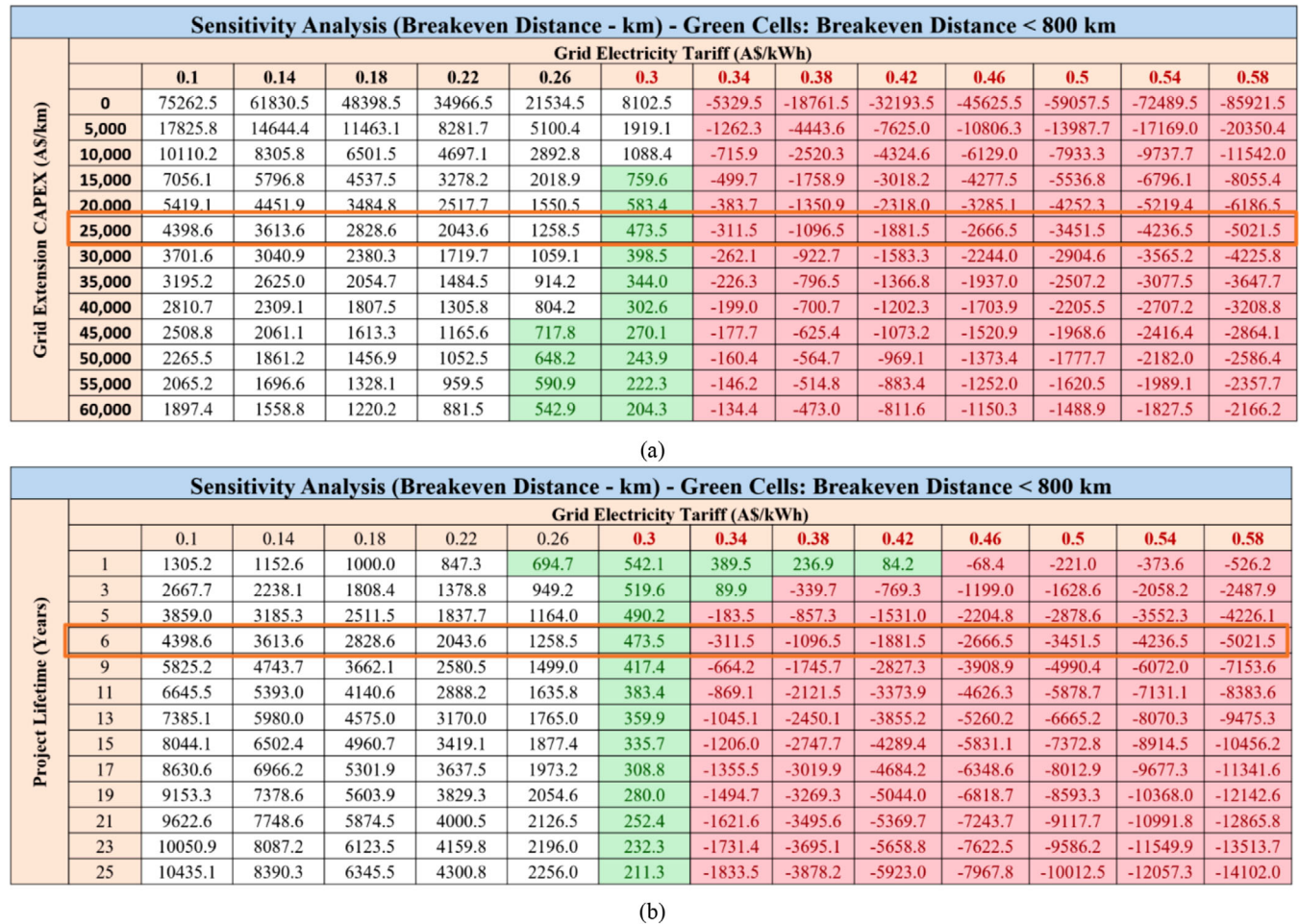


FIGURE 17 Grid extension breakeven distance sensitivity analysis due to the variation of: (a) grid electricity tariff and grid extension CAPEX and (b) mine lifetime and the grid electricity tariff. (Red: grid-extension is not viable, green: breakeven distance < 800 km, white: breakeven distance > 800 km)

HOMER Pro optimisation capabilities, the total NPC of the optimal on-site hybrid microgrid is compared against the grid extension and imported grid electricity total cost to calculate the breakeven distance between both alternatives. That being said, within the developed optimal hybrid microgrid sizing framework, the authors of this paper have also established an additional sensitivity analysis to investigate the impact of varying the grid electricity tariff and grid extension CAPEX on the grid extension breakeven distance in one scenario and the impact of mine lifetime and the grid electricity tariff on the grid extension breakeven distance in another scenario.

Grid electricity sales to mining sites can be part of mutual deals and agreements that are not easily accessible. Different numbers were found across Australia that ranged from 0.19 A\$/kWh to 0.65 A\$/kWh. Similar variability was observed for the grid extension CAPEX and OPEX per km. The following values have been used: 25,000 A\$/km (CAPEX), 300 A\$/km/year (OPEX) and 0.3 A\$/kWh (grid tariff) [68]. Figure 17(a) illustrates the sensitivity analysis results, where the NPC of grid extension versus the optimised South Australia on-site hybrid microgrid generation are compared to establish a breakeven distance between both options. A negative distance

indicates that the hybrid plant COE (0.324 A\$/kWh) is less than the grid electricity tariff, indicating that grid extension is always not viable. The variation of a hybrid microgrid power plant lifetime affects its NPC because of the re-occurring OPEX and fuel consumption, as well as the declining salvage value. The same re-occurrence is experienced for the grid tariff, which might experience additional fluctuations during the project lifetime. Varying NPCs are considered as an additional input for each lifetime in the sensitivity analysis to accurately assess their overall effect, as illustrated in Figure 17(b). The sensitivity assessment of grid extension versus hybrid microgrid power plant investment should thus be thoroughly investigated by the miner and the utility company considering the different explicit and implicit system inputs, and based on the mining site distance from the nearest grid point.

4.6 | Analysis of hybrid microgrid reliability

For mines, it is important to take into consideration that the optimal hybrid microgrid configuration can meet load demand without any shortage in electrical power continuously during

the mine's lifetime and this can be measured using loss of power supply probability (LPSP) investigator. LPSP is a relation between the shortage in energy demands when the generated and stored energy combined output is less than the load demand divided by the total load demand as:

$$\text{LPSP} = \frac{\sum_{t=1}^{8760} (E_l(t) - E_g(t))}{\sum_{t=1}^{8760} E_l(t)}, \quad (6)$$

where E_l is the demand load in kWh and E_g is the total generate power from the hybrid power system [69]. For instance, 100% LPSP means that the hybrid power system is totally reliable and has a zero capacity shortage. To ensure high system reliability, the maximum annual capacity shortage which is defined for HOMER as an input variable is set to zero to achieve 100% LPSP all-over the mine life time.

5 | DISCUSSION AND CONCLUSION

This paper presented an optimal sizing and profitability assessment framework for designing hybrid microgrids for mining applications. The framework optimises the size of each asset in the generation mix (e.g. diesel, RES and storage) in order to achieve the desired economic objectives while maintaining the technical constraints requirements. Three case studies were considered in Australia to cover a wide range of scenarios to test the framework. The case studies considered hybrid solar and storage technologies in addition to diesel for illustration, though the sizing framework can be similarly applied with different technologies such as wind. The three case studies were designed to cover the impact of: (a) mine's status (greenfield or brown-field mine), (b) mine's lifetime or PPA contract length, (c) various microgrid energy mix (fossil or hybrid), (d) wide range of renewable share percentages, (e) microgrid configuration (off-grid, grid connected), (f) natural resource variation (mainly solar irradiance) and available public grants. In all case studies, the salvage value of the hybrid system assets has been considered, which is an essential aspect given the relatively short lifetime of some mining projects against the assets lifetime (e.g. 6 years for DeGrussa vs an average of 25 years for PV panels).

Many large-scale projects still require significant incentives and grants to prove themselves profitable. While such grants remain to play a pivotal role in attracting hybrid microgrid investments in the mining sector, the results case study 1 illustrate that the rapidly declining cost of RES and storage assets may decrease the dependency on such grants for a project to take-off and be profitable, thus increasing the uptake of similar hybrid microgrids. Then, case study 2 demonstrated the increased design flexibility (and the positive impact on profitability) in greenfield projects since additional diesel generation capacity can be scrapped from the initial CAPEX investment when all the assets are designed simultaneously as compared to a brownfield case with existing diesel generation assets. On the other hand, case study 3 illustrated quantitatively the impact of environmental resources variations such as solar irra-

diance on the hybrid microgrid design in terms of the impact on both COE and assets sizing. Moreover, it presented a comparative methodology to assess the grid extension versus hybrid microgrid investment options for a mining project, establishing breakeven distance sensitivity as a function of grid energy cost and project lifetime.

Finally, results from the developed optimal hybrid microgrid sizing framework can help a variety of decision-makers, such as an IPP investigating the profitability of a hybrid microgrid project for mining industry; a mining facility owner who aims to establish and negotiate the economic terms of a PPA for procuring electricity for his mine, or a policy maker trying to set the effective policies and mechanisms to support the deployment of more renewables in different sectors, to steer in an effective path.

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