Regional and Remote Communities Reliability Fund Microgrid

MyTown Microgrid

Initial feasibility results for a town microgrid

Heyfield local energy options: techno-economic analysis

Milestone 4.2a – July 2022

Research Team

Work Package Lead: Jay Rutovitz, UTS

Research team: Heather Smith, Dr. Soheil Mohseni and Dr Jihane Assaf (UTS), Dr. Rakib Shah (Federation University, Australia), Anne Callies (RMIT), and Craig Memory (PIAC)

Chief Investigator: Dr. Scott Dwyer, UTS

Key support

Federation University Australia

Wattwatchers Digital Energy

AusNet Services

Heyfield Community Resource Centre

Latrobe Valley Authority

About the project

MyTown Microgrid is an innovative, multi-year, multi-stakeholder project that aims to undertake a detailed data-led microgrid feasibility for the town of Heyfield (Victoria), built on a platform of deep community engagement and capacity building.

The project received funding under the Australian Government's Regional and Remote Communities Reliability Fund Microgrids stage 1 funding round. It also received funding from the Latrobe Valley Authority as part of the Gippsland Smart Specialisation Strategy.

Citation

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Executive Summary

The MyTown Microgrid project is developing an innovative data-led approach to local energy solutions, starting with the town of Heyfield in Victoria. Built on a platform of deep community engagement and capacity building, the project is also creating the knowledge and tools to make it faster, easier, and cheaper for other regional communities to understand the proposition for microgrids for their towns.

This summary report is the product of an initial techno-economic feasibility study, which aims to guide the project team and community in which local energy solutions should be the subject of more detailed technical and costing analysis. The findings from this assessment are:

- A microgrid in Heyfield is technically feasible.
- Economic viability would only be likely with bioenergy at the local timber manufacturer, Australian Sustainable Hardwoods (ASH) having a key role in the microgrid. Even this positive economic case comes with a number of caveats and could be a high-risk venture for the community and ASH. More detailed analysis would be required to fully understand the economic proposition.
- From a regulatory point of view, an enormous amount of complex negotiation would be needed, and any such proposal may still be turned down by the energy regulator. None of the standard exemptions apply, and there is no clear route to comply with required consumer protections.

A further, more detailed costing and technical investigation of the Heyfield town microgrid option is not recommended by the project team. Instead, we suggest that the community considers other local energy solutions - identified as part of the project – that best align with their aspirations. These alternative options could help increase the amount of locally generated clean energy, reduce energy bills, help improve energy reliability and resilience, and drive local socio-economic benefits. Options include things such as a town-scale program of energy efficiency and load control upgrades or community batteries.

Whether a microgrid is a desirable option for Heyfield is ultimately a decision for the community. The initial assessment of the project team is that the risks are high, and that it would bring no clear economic advantages.

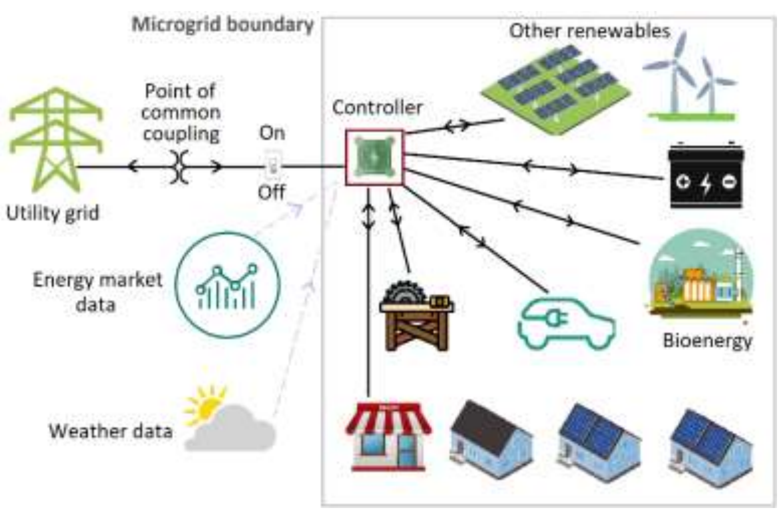
Introduction

What is a microgrid?

A grid-connected microgrid can be defined as "*a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries* ***that acts as a single controllable entity with respect to the grid***." A key characteristic is that from the network point of view the microgrid is a single entity, with an on/off switch and a meter point.

The microgrid produces energy for consumers within the microgrid, exports to the grid when there is surplus, and purchases energy from the grid. It normally operates in a grid-connected mode but can 'island' and continue to supply electricity if the electricity grid goes down (see Figure E1).

Figure E1 Overview of the microgrid concept



The term 'microgrid' has spawned many different definitions and is frequently conflated with other local energy solutions such as community batteries, virtual power plants, or peer-to-peer trading. These options all aim to make better use of rooftop solar PV and (where possible) battery storage. The key difference is that a microgrid is behind a single on/off switch and can provide an electricity supply when the utility grid goes down.

How did we test the feasibility and viability of the microgrid?

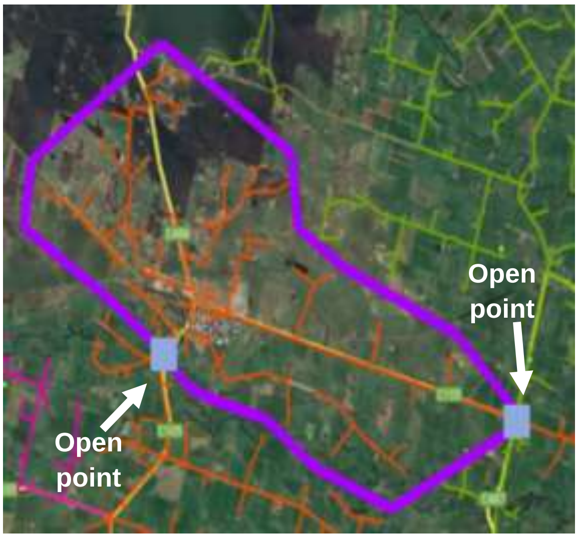


Figure E2 The town microgrid boundary

A microgrid needs a disconnection point from the main grid, and the technical and economic assessments need to understand the electrical load and generation within the microgrid. The first step was to define the boundary[a], shown in Figure E2. There are several stages of assessment:

The technical feasibility used specialised software to simulate loads and generation at times when equipment is likely to be stressed. It aimed to find out whether the microgrid could keep operational conditions within reasonable limits, how much power the microgrid could export, and find out the cost of the microgrid equipment.

The regulatory feasibility looked at the rules and regulations concerning microgrids in order to find out whether a town microgrid would be legally possible, and what it would involve.

The economic feasibility calculated the cost to set up and run the microgrid, how much generation and storage would be needed, and whether different stakeholders would be better or worse off.

The timber manufacturer within the town means there may be an option to have a large bioenergy plant. This would change the other generation and storage options needed to allow the microgrid to island (operate independently from the grid if needed) very significantly. We, therefore, looked at two scenarios, one without the bioenergy plant (and the timber manufacturer) and one with them.

Technical and regulatory feasibility assessment

Regulatory feasibility

The regulations as they relate to microgrids are not clear cut, so there it is not a simple answer as to whether a town microgrid is feasible from a regulatory point of view. It is clear that the establishment and operation of a town-sized microgrid would be enormously complicated and fraught with risks. A distribution license and a generation license (or exemptions) would be needed. However, the automatic exemptions for embedded networks do not apply as the town network would cross property boundaries and contains a large number of customers. A distribution license is needed unless the network was operated by an entity with a license, such as AusNet Services. An electricity retail license or an exemption would also be needed (although it is likely that a retailer would be needed anyway).

Apart from licensing, the microgrid arrangements would need to ensure that consumer protection laws are maintained. This means consumers must keep the option to leave the microgrid retail system and ensure that consumers will not be paying more for their electricity under the new arrangements. It is difficult to see how this could be achieved.

Technical feasibility

This study aimed to find out the amount of generation the microgrid could support, the limits on export and import, the additional control infrastructure needed (and costs) with different amounts of local renewable generation, and the impacts of the microgrid on the reliability of the system. While these are initial findings only, the results indicated:

[a] Aa microgrid has a sharp boundary, whereas for many local energy options people can opt in or out.

- The medium voltage network in Heyfield could support a microgrid with a load well above the current peak, and host sufficient PV and other local generation to reach more than 80% of local generation.
- There is an export limit of about 1.7 MW as a result of constraints on the supply feeder from Maffra.
- The CAPEX of microgrid components (excluding those directly associated with the new generation) is between $0.5 – 0.8 m in most cases.
- There is better reliability overall with the microgrid option compared to the grid-only option.

Economic viability assessment

Economic viability

The economic viability of the microgrid was investigated using the HOMER model. The optimisation process finds the system configuration that gives the lowest total discounted system cost, using the candidate technologies and within any specified constraints. As well as finding the optimal amount of generation and storage in each scenario, sensitivity analyses were undertaken to test changes in the key inputs, such as the cost of the bioenergy fuel. Figure E3 summarises the inputs, outputs, and processes.

Two primary scenarios were considered, considered, one with and one without bioenergy. The optimisation software assumes that any resource within the microgrid is operated in an integrated manner. This would mean, for example, that the timber manufacturer load would use solar at times when that is most economic for the entire system (for example, when it would otherwise be curtailed), and that the bioenergy plant would be operated when there is a lack of output from the solar PV.[b]

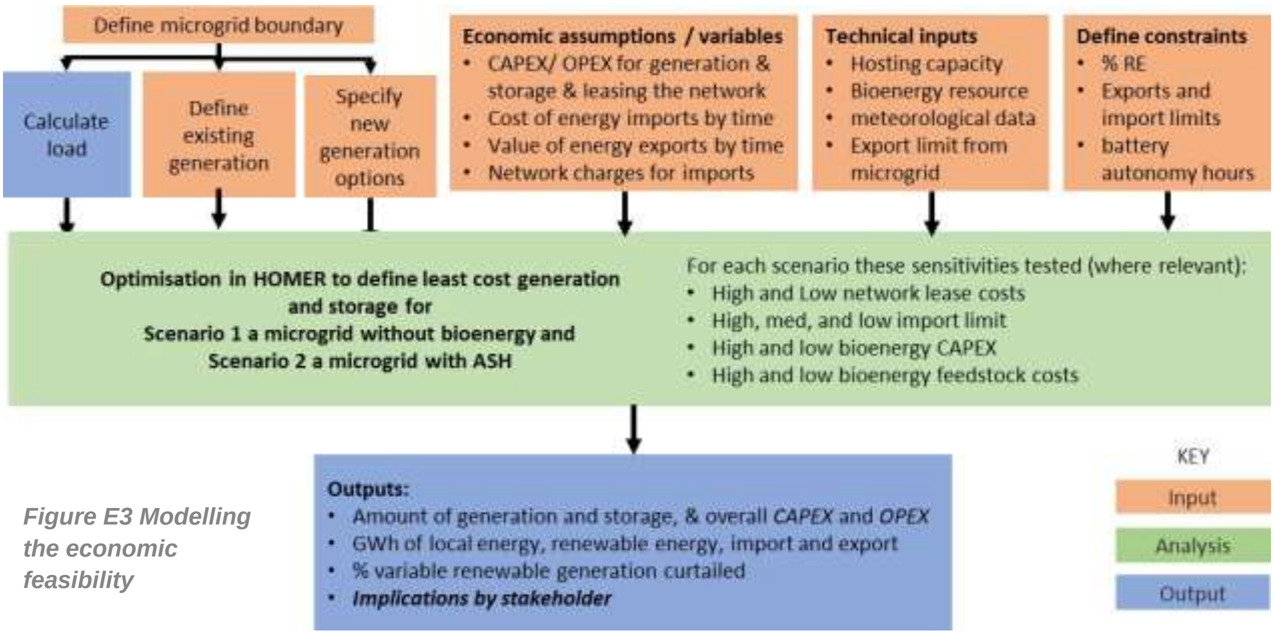


Figure E3 Modelling the economic feasibility

We set a limit on the amount that could be imported from the grid at any moment, and tested limits of 1 MW, 1.5 MW and 2 MW for each scenario (when the model was run without import limits, little additional generation was installed, as it proved cheaper to import energy from the grid).

Economic modelling results

In scenarios without bioenergy, the net percentage of local electricity supply[c] varies from 94% with an import limit of 1 MW, to only 47% when the import limit is set at 2 MW. As a community aspiration is to increase the

[b] Early results showed that centralised solar PV panels and wind turbines are more expensive than rooftop solar PV and bioenergy technologies, which meant they were never selected in the optimisation model.
[c] Defined as the MWh of local generation divided by the energy consumed within the microgrid.

amount of local generation, and the current percentage of local electricity is close to 40%, this scenario is not considered suitable. In the cases with 1 and 1.5 MW import limits, 94% and 71% net local generation is reached, respectively. Curtailment increases as the import limit decreases as there is also a technical limit on exports and the import limit means there is a lot of excess generating capacity.

Table E1 Physical results and initial CAPEX
(only the higher bioenergy CAPEX & fuel costs, and the higher network lease costs are presented)

	Initial CAPEX	Local supply	Battery autonomy	Curtailed generation	New generation
Scenarios without bioenergy					
Import limit 1 MW	$49 m	94%	12.3	37%	16.0 MW PV, 26 MWh storage
Import limit 1.5 MW	$20 m	71%	3.4	13%	7.0 MW PV, 7 MWh storage
Import limit 2 MW	$9 m	47%	0.5	0%	2.5 MW PV, 1 MWh storage
Scenarios with bioenergy					
Import limit 1 MW	$27 m	96%	1.9	4%	6.0 MW PV, 5.5 MWh storage, 2 MW bioenergy
Import limit 1.5 MW	$21 m	82%	0.5	3%	5.2 MW PV, 1.5 MWh storage, 2 MW bioenergy

Local supply percentage is higher in the bioenergy scenarios. The net percentage of local electricity supply varies from 82% in the higher cost bioenergy case where the import limit is 1.5 MW, to 96% where the import limit is set at 1 MW.

Looking at the scenarios without bioenergy, initial CAPEX varies from $20m – $48m if the scenario with high imports is disregarded. With bioenergy, the initial CAPEX varies from $21m to $27m.

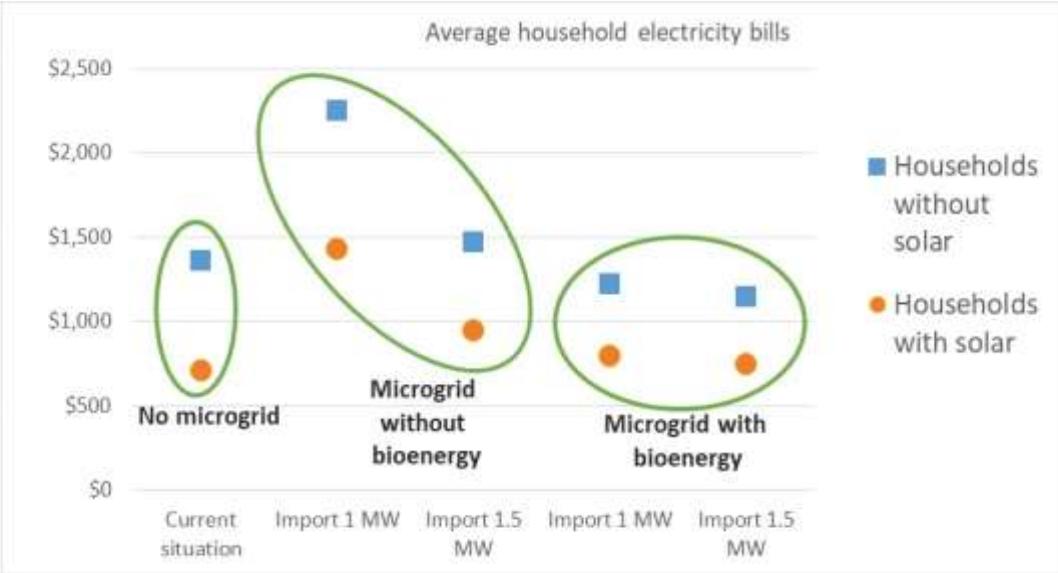


Figure E4 The effect of a microgrid on average household electricity bills in Heyfield

Looking at the estimated impact on resident bills, all the scenarios without bioenergy result in bills going up, by between 8% and 100%. Residents with solar are worse off because they currently get feed in tariffs for solar exported to the grid[d], which will not be available if they become part of the microgrid, so bills go up even in cases where the microgrid energy costs are fairly close to the baseline. The scenarios with bioenergy result in bills going down for residents who do not have solar installed, by between 10% and 25%. Residents with solar are worse off, by between 5% and 11%.

[d] Bill calculations assume the feed in tariff is valued at 4c/kWh; some residents will currently receive more than this so they would be more badly affected by the change.

Conclusions and next steps

This analysis aimed to find out whether a town microgrid in Heyfield is feasible and viable. Some conclusions can be drawn even from this initial study:

- Is a town microgrid technically feasible? – yes.
- Is the microgrid feasible from a regulatory point of view? While there is no clear conclusion, it would certainly involve an enormously complex negotiations and may still be turned down by the regulator. None of the standard exemptions apply, and there is no clear route to comply with required consumer protections.
- Is the microgrid economically viable? without bioenergy, no; with bioenergy, yes (with caveats). To know with certainty a microgrid with bioenergy is economic would need more detailed analysis. However, there are very high risks whether economic or not, as the generator would need to be run in an entirely integrated manner. This would mean operating according to the needs of the entire system, including shutting down and using solar PV when there is excess PV generation. This is a high-risk venture for both the business and the community.
- Is the microgrid desirable? This is a decision for the community, however, there are no clear economic advantages, and the risks are very high.

There are conditions that could alter the outlook for any community wishing to investigate a microgrid. The first, and perhaps the most important, is 'network pain' – that is, are there significant network problems that are costing a lot of money. If these are sufficient that the network business might want to implement a microgrid, there would be both financial support and a much easier path to regulatory compliance. However, this is very unlikely to apply in Heyfield. A significant reduction in battery costs and implementing a high degree of load flexibility would also improve the economics.

Overall, further investigation of the Heyfield town microgrid option is not recommended. We recommend instead that the community considers which of the other prospective local energy options or combinations of options are most aligned with community aspirations. Some of the options worth investigation are shown in Table E1, with a note on how they compare to previous community aspirations.

If the Heyfield community wishes to implement local energy options, other than as private individuals, a community body will be needed to make decisions, enter into negotiations, promote the solutions, and potentially own or lease assets (this would have been the case for a town microgrid as well). It is recommended that the Community Reference group consider implementing such a body, with the first task to help decide which of these immediate energy options is the subject of the remaining effort in this project.

Table E1 Local energy options compared to some community aspirations

	↓ energy bills	↑ reliability & resilience	↑ community involvement	↑ environmental benefit	↑ Future - - proofing
Town microgrid	✗	✓	✓	✓	?
Energy efficiency upgrade program	✓	✓	✓	✓	?
Load flexibility & control[e]	✓	✓	✓	✓	✓
Community battery	?	✓	✓	✓	✓
Community renewable generator	✗	✗	✓	✓	✗
Community retailer	?	✗	?	?	✗
Stand-alone power at critical sites	✗	✓	?	✗	✗

[e] Likely to be implemented with an energy efficiency upgrade, although the technical assessment may be separate.

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List of abbreviations

Abbreviation	Description
ABS	Australian Bureau of Statistics
ASH	Australian Sustainable Hardwoods
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
DERs	Distributed Energy Resources
DNSP	Distribution Network Service Provider
ENS	Energy Not Supplied
FIT	Feed-in-Tariff
GEO	General Exemption Order 2017 (of the Electricity Industry Act 2000 (Vic))
GIS	Geographical Information Systems
ICT	Information and communication technology for microgrid
kV	Kilovolts
LCOE	Levelised cost of energy
LV	Low voltage
MFA	Maffra Zone Substation
MV	Medium voltage
MVA	Mega-volt ampere
MW	Megawatt (a measure of power or load)
MWh	Megawatt hours (a measure of energy)
NEL	The National Electricity Law
NER	National Electricity Rules
NEVA	The National Electricity Victoria Act 2005
NMI	National Meter Identifier
PV	Photovoltaic (Solar)
RIN	Regulatory Information Notices
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Frequency Duration Index
SDME	Spatial Data Management Environment
SSC	State Suburb Classification
VAR	Volt ampere reactive

1 Introduction

The Heyfield MyTown Microgrid project is undertaking a detailed data-led microgrid and energy solutions feasibility for the town of Heyfield (Victoria), built on a platform of deep community engagement and capacity building. Over the three-year duration, the project will also develop the knowledge and tools to make it faster, easier, and cheaper for other regional communities to understand microgrid and other energy solution propositions for their community.

This initial feasibility analysis of a town microgrid option for Heyfield is associated with the Techno-Economic Work Package 3 and is part of milestone 4.2, Analysis Results (Detailed feasibility and costing analysis of microgrid elements).

This report builds on Milestone 3.4, Part 1 Energy options: initial results, and Milestone 3.4, Part 2 Boundary options: revised results.

This report covers the general process for initial modelling and analysis to test the feasibility of a microgrid, and the specific process followed in this case. It includes:

- An overview of the modelling process used
- The selection of the specific modelling tool

The data and inputs required

The process of obtaining data from the network service provider

- The approach and initial results for whether the Heyfield town microgrid is technically feasible
- An initial assessment of regulatory issues
- Initial results for viability from the economic modelling
- A discussion of what this means for the feasibility, viability, and desirability of the town microgrid.

The aim of this initial feasibility is to give indicative results that are sufficient for the community to determine whether it is worthwhile pursuing further analysis of a town microgrid. If the community does wish to pursue the microgrid option further, the next step would be more detailed studies. Otherwise, the modelling and research effort in the project could be directed to alternative local energy options.

2 Modelling a microgrid – overview

2.1 What is a microgrid?

A microgrid rests on three main pillars, namely: local generation, independence, and intelligence[f]. More specifically, a grid-connected microgrid can be defined as "*a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid*"[1]. That is, a microgrid produces energy for customers within the microgrid; it may also export surplus energy to the grid, and purchase energy from the grid. Microgrids avoid some of the inefficiencies of large-scale generation of centralised power plants, which require transmitting electricity over long distances. Depending on the surrounding network situation, a microgrid can provide network benefit by deferring the need to invest in network augmentation to deal with the projected growth of electrical loads, for example due to the increasing electrification of the transport and heating sectors.

> a grid-connected microgrid can be defined as a group of interconnected loads and distributed energy resources … that acts as a single controllable entity with respect to the grid.

Figure 1 shows a schematic diagram of the grid-connected microgrid concept[2]. The microgrid generally operates in a grid-connected mode for both efficiency and cost-effectiveness. The grid connection helps soak up excess renewable power generation in times of surplus and avoid curtailment of local generation and helps maintain voltage and frequency within acceptable limits[3].

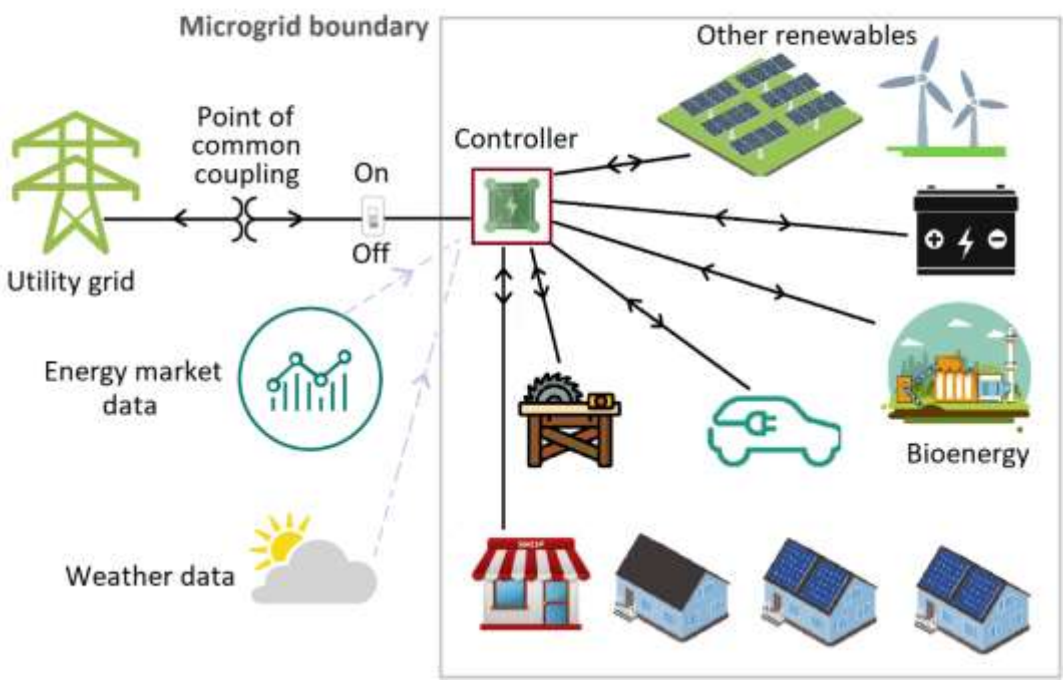

Figure 1 Overview of the microgrid concept

Integration of dispatchable generation (such as bioenergy) and energy storage systems in microgrids increases system flexibility, enabling optimal utilisation of variable renewable energy resources like solar

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[f] The microgrid controller provides the most important intelligence, as it brings the ability to control loads, generation, and storage to balance supply and demand within the microgrid.

photovoltaic (PV) and wind energy. Such dispatchable distributed energy resources provide an effective way to avoid overbuilding variable renewable technologies to manage supply and demand fluctuations. In the absence of dispatchable resources, significant spare capacity is needed to achieve high renewable energy fractions. In addition, limits on the network supplying the microgrid may prevent the export of excess local generation back to the grid, thereby leading to curtailment[4].

Battery energy storage systems are one of the solutions for reducing renewable energy curtailment. They can store excess locally produced electricity, and electricity drawn from the grid during off-peak times, for use at times of higher electricity prices which will often correspond with low solar generation. This potentially improves the economics of microgrids with high levels of variable renewables integration[5]. Moving loads into daylight hours and developing flexible loads with control are the other main strategies for reducing renewable energy curtailment.

Independence is the second principal feature of a microgrid, which can disconnect from the wider utility network and operate in an independent (autonomous) manner. This is called “islanding” and enables a microgrid to break off and provide a power supply by operating on its own local energy generation and storage devices. A microgrid is designed to move into island mode and take over control of balancing supply and demand whenever the main grid is unavailable. Microgrids can therefore improve energy resilience and reliability, helping communities avoid blackouts or restore power quickly if one happens. During natural and climate disasters, especially high impact, low probability events such as bushfires, during regular storms, failures and faults, or for other more prosaic reasons (such as maintenance), a switch can isolate the microgrid from the utility grid automatically, and function as an “island”[6].

Microgrids rely on intelligent controllers to best manage the dispatchable resources – energy storage and fuel-fired generation components – in the presence and absence of weather-dependent technologies[7]. The dedicated microgrid controller also provides an effective platform for the implementation of demand response programmes and harnessing the demand-side flexibility potentials of small-to-medium loads.

A key characteristic of a microgrid is that from the network point of view, the microgrid is a single entity with an on/off switch and a meter point[g]. This is key to the business case as exchanges within the microgrid do not attract network charges, and the microgrid benefits from bulk energy supply.

The term ‘microgrid’ has spawned many different definitions and is often applied loosely to many distributed energy options, so it is worth noting what a microgrid is not. The term is frequently conflated with other local energy solutions such as:

- Community battery – this is a battery shared by different customers, located behind its own meter rather than behind the meter at a customer premises. Community batteries may have multiple objectives, such as improving the amount of solar that can be used or installed locally and provide an alternative to multiple individual batteries at customer premises. Community batteries may also be a means to improve network operation.[h]
- Virtual Power Plant (VPP) – VPP refers to the idea that if you can control multiple small systems scattered across a region, it can behave as if it is a large-scale generator. The main purpose of VPP’s is to interact with the wholesale electricity market and VPP operators. VPPs cannot coordinate to manage electricity supply when the grid fails, as they do not have physical infrastructure which operates independently of the grid.
- Peer to Peer trading – is an administrative mechanism for co-ordinating electricity purchasing arrangements between renewable electricity generators and loads; a number of trading platforms have been designed to do this. To date, these operators have remained small. Some form of

[g] Unless the microgrid is operated by the network business, in which case it may not be metered.
[h] The Victorian government has funded feasibility studies for community batteries, and trials have been underway with network businesses in WA and NSW. These projects share a desire to find business models to support a battery investment, which is generally not economic within current tariff structures. None of these projects to date have incorporated the ability for the to control electricity supply and keep the battery operating in island mode if the grid fails.

electricity retail arrangements is still required to fill in the gaps between the physical electricity flows and the accounting arrangements between the generator and the customer.

All of the above arrangements are local energy solutions that aim to make better use of rooftop solar PV and, where possible, battery storage; the last two (VPP and peer to peer trading) are administrative arrangements for selling and dispatch. The key difference with these examples is that a microgrid is behind a single on/off switch and is able to provide an electricity supply when the utility grid goes down.

Stand Alone Power Systems (SAPS) are not connected to the grid. They can supply a single home or building, or a microgrid which is not connected to the main grid. SAPS are increasingly used by network businesses seeking to replace long isolated lines with a single container holding a battery, diesel generator and solar system. Hybrid Solar-Battery Systems can be defined as those arrangements that can act as a SAPS when the grid is unavailable but are grid connected systems for the most part.

2.2 Model elements and analytics framework

The aim of a computer model for the simulation of a microgrid is to assist in the evaluation of whether a microgrid is technically feasible and economically viable. This modelling represents the 'analytical engine' shown in *Figure 2*, which is taken from the analytical framework report for the project[8].

This report is an initial evaluation to determine whether more detailed studies are worthwhile. As it is initial, some of the analyses shown in *Figure 2* have not been carried out, in particular testing a potential microgrid against future loads and developments.

The model is aimed at optimisation, that is, finding the cheapest combinations of power generation and storage technologies. To this end, a microgrid's physical behaviour and its whole-life cost – the total cost of installing and operating the system and any associated generation and equipment over the project life span – need to be modelled.

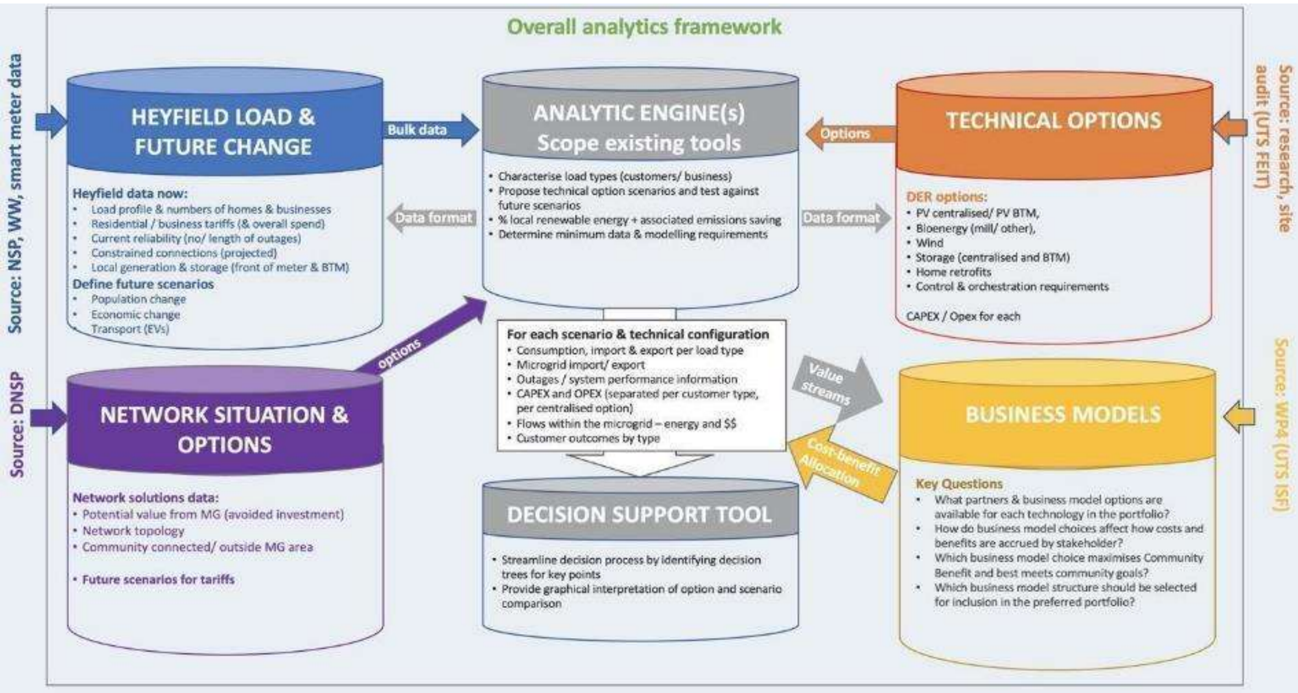


Figure 2 Summary analytic framework
(from Conceptual Data and Analytical Framework, Milestone 2.5 – June 2021)

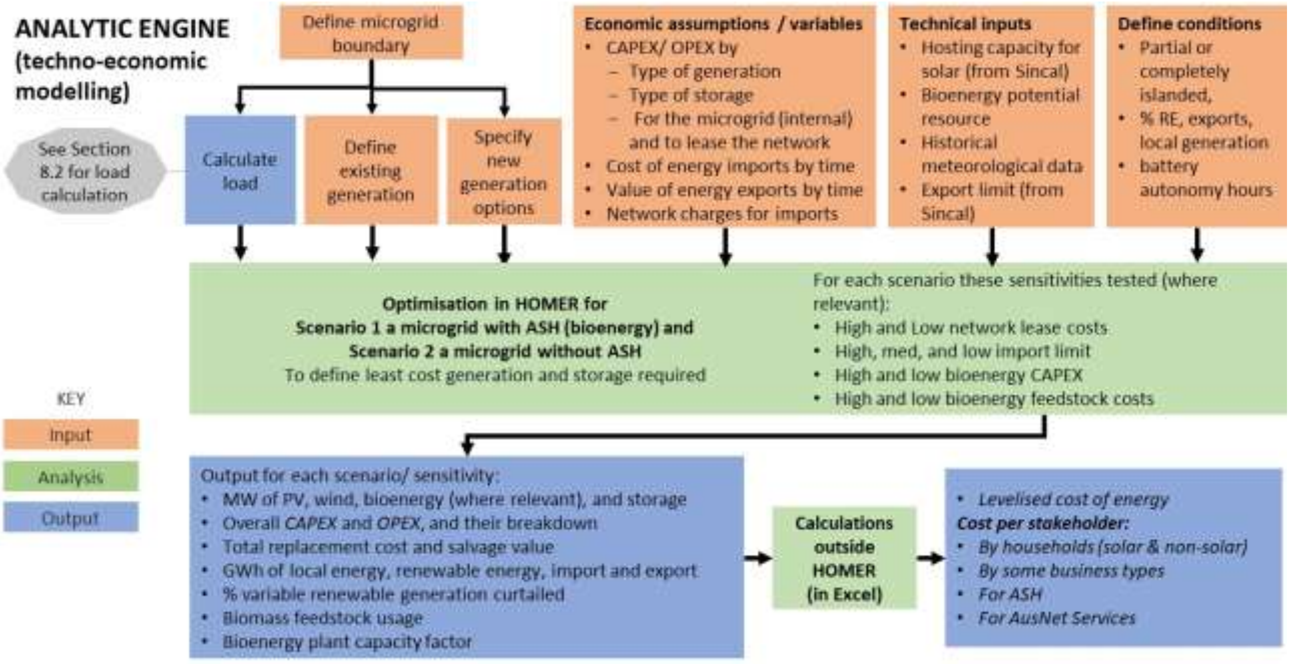
Computer models for microgrid simulation also provide a platform for the comparison of different design choices based on technical or other requirements (for example, the proportion of locally generated energy, or the ability to operate for a certain amount of time in island mode). This enables checking the sensitivity of the total cost to changes in key input parameters to support more informed decision-making. It also helps identify the main sources of uncertainty and their risk implications[9].

Computer models tailored to the analysis of microgrids allow for exploring the techno-economic trade-offs in the microgrid – such as the trade-offs between cost, or saving money on power bills, increasing energy resilience (defined as the ability to maintain power in an emergency) and self-sufficiency (defined here as the net proportion of load met by local generation).

Figure 3 is a flowchart of the analytic engine, illustrating the key inputs, the main data sources and steps undertaken during the techno-economic modelling, including the main scenarios considered, the key outputs, and the key indicators used to develop preliminary conclusions.

In the first step, all input data are loaded into the analytic engine. The model (HOMER) then solves several instances by finding the least-cost energy mix solution for different scenarios (optimisation), which provide the context for performing sensitivity analyses. The following paragraphs explain in greater detail how the main three tasks associated with the techno-economic modelling build upon each other.

It should be noted that all the analyses in this report are conducted without taking energy efficiency and demand-side management interventions into consideration. If this evaluation is positive and leads to a community decision to pursue the microgrid option further, further analysis would be undertaken to find the optimal mix of candidate technologies including generation, storage, energy efficiency upgrades and load flexibility.



2 Analytic engine - overview

The overall microgrid techno-economic simulations consist of three main stages, namely:

(i) Collecting and processing input data, in accordance with the defined microgrid boundary, and defining the associated conditions.

(ii) Optimisation of the mix of generation, storage, and import/ export from the grid, for each of the scenarios (which each have a set of technical constraints).

(iii) Conducting sensitivity analyses by running the model, populated for the microgrid case (scenario) of interest, using different combinations of input data values.

One of the greatest challenges in conducting techno-economic assessments is obtaining input data that is representative of reality. As Figure 2 shows, there are many input parameters. These include the techno-economic specifications of the candidate technologies for integration into the microgrid and time-series data for power load, meteorological conditions, and the wholesale electricity price. There are also underlying parameters for discounted cash flow analysis, such as the project lifetime and interest rate. Refer to Section 3 (Data and inputs) for an in-depth discussion of the input data needs, data availability, and main sources, and to *Appendix C Inputs and assumptions for economic modelling* for a list of input parameters and assumptions. The overall microgrid topology and the system conditions under optimisation also need to be specified.

In the optimisation layer, the optimal sizing and dispatch strategy of the technologies in the candidate pool are determined. This is because power loads must be met at every time-step of the year-long operation of the system by some combination of available local generation, local energy storage, and imported grid electricity. The choice of energy source (local generation, local storage, or via imports) is selected to obtain the minimum discounted life-cycle cost for the system[10]. During normal grid-connected operation, the optimisation software seeks to maximise the economic gain whilst maintaining energy balance between generation and load, ensuring that voltage and frequency remain within the established boundaries[11]. The timing of loads and generation is a fundamental aspect of a robust microgrid optimisation solution.

The output of the optimisation model is a cost-optimal set of capacities for the candidate technologies, the output time series data of power exchanges with the upstream utility grid, and the total net present cost of implementing the conceptualised microgrid and its components. The net present cost includes the discounted values of all costs and revenues (capital investment, replacement and operation costs, salvage value of the integrated energy infrastructure, cost and revenues from energy exchanges with the utility grid, the lease or purchase cost of the network assets that make up the microgrid, and the operational costs associated with the microgrid itself)[12].

A breakdown of how energy is supplied in the cost-optimal mix is also provided. For bioenergy integrated cases, this incorporates the biomass feedstock usage, the proportion of energy consumption supplied by bioenergy, and the bioenergy plant capacity factor. In the current evaluation, it is assumed that the supply-demand balance profile is repeated for each year in the project life span.

Several indicators are calculated outside the HOMER model, including the levelised cost of energy, the implications for different customers' power bills, the system's self-sufficiency, and various network charges on imports[i]. These are discussed in more detail in Section 6 (Is a town microgrid economically viable?).

Finally, in the sensitivity analysis phase, the type of components and the microgrid topology are held fixed except for key parameters (for example, network lease cost) whose relative importance on the economic viability are under consideration. Multiple model runs are carried out in the sensitivity analysis process, each varying the key parameters to reveal how sensitive the outputs are to changes in these inputs. The sensitivity analyses help identify the best-case and worst-case scenarios with respect to those variables, and thus provides an indication of how robust the analysis is. It is also useful for analysing the effects of uncertainty and the relative importance of key inputs. As summarised in Figure 2, the following sensitivity variables[j] are considered: (i) network lease costs, (ii) the import limit, (iii) the capital cost of the biopower plant, and (iv) the biomass feedstock costs.

Sensitivity analyses can be performed with any number of variables, and each combination of the possible values for the variables defines a separate optimisation case. For instance, assuming two values for network costs, three values for the import limit, two values for the biopower CAPEX, and two values for the biomass feedstock cost leads to 2 × 3 × 2 × 2 = 24 distinct cases. These analyses enable insight into the relative effect of particular variables on the results by covering their likely ranges in the simulations.

2.3 Boundary selection

Four boundary options were examined, ranging from a selection of critical sites in the centre of Heyfield (Boundary 1) to one which encompassed multiple townships (Heyfield, Denison, and Winnindoo). A

[i] LCOE calculated within HOMER does not fit the current standard definition so has been calculated externally, and HOMER does not include several of the desired output parameters and metrics.
[j] The variables for which the modeller has entered multiple values.

boundary option referred to as ‘Boundary 0’ is also considered which has no boundary limitation and involves increasing the efficiency and flexibility of home and business energy use (this is not a microgrid option).

It was seen as desirable to examine a microgrid encompassing just the town centre, as this reflected community aspirations, which was to be Boundary 2. However, the physical characteristics of the network meant the centre of town could not be separated on the medium voltage network as there are no suitable connection and disconnection points, and areas outside the town would be left without power. Reduced scale options involving just several feeders (2A, 2B, 2C, 2D) were briefly considered, but these are unlikely to be possible without excessive technical difficulty and expense. Boundary 2 was therefore abandoned.

Boundaries 3 and 4 remain as potential microgrids, with boundary 4 having considerably greater geographical coverage. It was decided that Boundary 3 should be the option for further technical and economic feasibility studies with the main connection point to the grid at A (see the revised boundary option report for more details[13]).

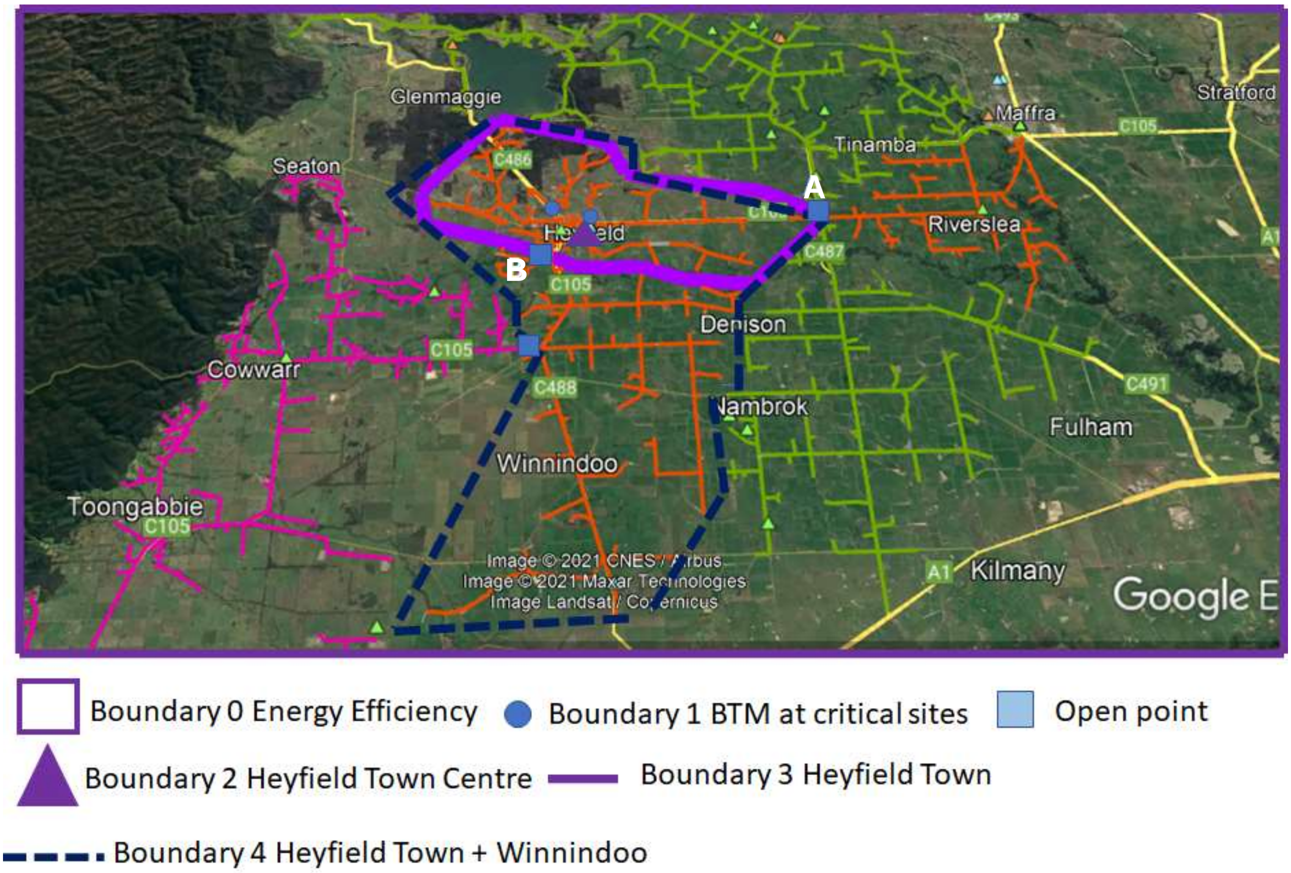


Figure 3 - Boundary options for a Heyfield microgrid (revised).

3 Data and inputs

3.1 Data needs – overview

This project is taking a data-driven, simulation-based approach, and finding and processing the right data to put into the analytic engine forms an integral part of the long-term strategic energy planning exercise.

Data requirements in early-stage grid-connected microgrid feasibility can be broadly categorised into the following areas:

- Load demand and characterisation (including load profiles and type)
- Defining existing generation, such as existing installed rooftop solar PV systems
- New energy options with their associated technical (such as efficiency, expected lifetime, and degradation rate) and economic (CAPEX, OPEX, and replacement cost) specifications.
- Resources (such as meteorological data for wind and solar and biomass feedstock availability), in accordance with the candidate technologies selected for integration into the microgrid.
- Economic assumptions, such as wholesale electricity market prices (which form the basis for formulating the import and export rates), network charges, network lease costs, feed-in-tariff, and inflation and discount rates.
- Technical inputs related to the wider project, such as the project lifetime and control parameters pertaining to the scheduling of the dispatchable units.
- Operational- and planning-level constraints, such as technical constraints on renewable energy penetration, operating reserve[k] in a microgrid context[14].
- the parameters that are used to measure the level of self-sufficiency, as well as the potential sale and purchase capacities in power exchanges with the utility grid.
- Fixed cost factors that do not form part of the optimisation process[l] but do influence the economic outputs, such as the CAPEX of additional equipment required to implement a microgrid, voltage regulators and microgrid controllers, or the operational costs of the microgrid itself.
- Future projections: depending on the level of accuracy required, the modelling may include future projections for load, charges, and component CAPEX.

3.2 Data availability

Obtaining data for microgrid techno-economic analyses is always challenging, particularly for grid-connected microgrids where electricity services are already available. It is often difficult to know which inputs are worth a lot the effort to get highly accurate data. Approximate estimates of important variables, such as network lease costs, the import limit, or retailer charges can be used in the initial techno-economic analysis, where the overarching goal is to produce indicative results to see if a microgrid solution would be a real option and is worth more detailed investigation.

Sensitivity analyses are performed on the variables for which accurate data is time-consuming to obtain and/or those that are likely to be of critical importance during initial modelling. The sensitivity analyses will also help inform the decision-maker of the value of expending time or effort in improving the accuracy of those inputs.

[k] Operating reserve is the surplus power generation capacity that is operating and can respond instantly to a sudden increase in load or a sudden decrease in the power output from renewable energy generation technologies. It is similar in concept to spinning reserve, but additionally encompasses components that do not spin within a microgrid context, such as the battery bank and the wider utility network.

[l] CAPEX and OPEX that are held constant.

Within the economic feasibility modelling of this study, the most challenging data to obtain were as follows:

(i) Adequate load data. There were multiple issues involved in calculating the load. Feed-in-tariff programmes are in place, so only net-metered energy consumption data is available at the entry point to the LV network, and there is a lack of data on self-consumption of solar PV. It was difficult to find accurate estimates of the installed capacity or output of rooftop PV. Loads are either very poorly characterised or not characterised at all, even into residential or commercial.

(ii) The sale capacity (i.e., the maximum power that can be sold back to the grid at each point in time) is important and requires detailed technical feasibility modelling (see *Section 4 Is a town microgrid technically feasible?*),

Many types of input data from a variety of sources were used to populate the HOMER model. Table 1 summarises the key purposes and types of data needed for the feasibility, and *Appendix C Inputs and assumptions for economic modelling* provides details of the actual model inputs and the associated sources.

Table 1 Purpose and types of data used in the optimisation model

Purpose	Data required	Comment/ availability
Calculating load	Top down: SCADA data	30-minute network data for the year 2020 was obtained and manipulated to calculate the load.
	Bottom up: Wattwatchers or smart meter data	These can be obtained from smart meter data (with customer permission) or from consumer monitoring devices such as the Wattwatchers devices. The smart meter data was not available, and there was not 12 months of data available for a sufficient number of Wattwattchers devices when the analysis started.
	Estimate of self-consumption	This is needed to model loads and generation in the microgrid situation, as self-consumption should be included in the modelling. This information varies across load types and can be calculated from Wattwatchers data.
	Load characterisation	Loads should be characterised into customer type (residential or business), and ideally into sub-loads such as hot water and heating. This would allow testing options like load shifting. This information was available from Wattwatchers devices but was not paired with sufficient contextual information to be utilised in this analysis.
Defining existing generation	Details of PV installed	MW installed, approximate age, and details of the tilt angles of the PV panels (in this study these were classed as north-east- and north-west-facing).
	Other existing generation	For further study, details of any existing back up generation and/ or storage should be included.
Defining new generation and storage options	CAPEX	The initial capital cost, which occurs in year zero.
	OPEX	The annual operation and maintenance cost, which accounts for the fuel cost (where appropriate).
	Replacement cost	Incurred each time the component needs replacement at the end of its lifetime.
	Lifetime	Can be specified in years or operational hours – this was needed in order to factor replacement and salvage value into the calculations.
	Efficiency	Round-trip efficiency for storage devices and for bioenergy conversion.
	Resources	Renewable resources need to be quantified, in particular biomass fuel availability and cost, and wind and solar resources (from weather data).

Purpose	Data required	Comment/ availability
Calculating the import and export rates	Wholesale electricity market prices	Reflecting the value of the wider utility network in absorbing excess generations (and hence reducing curtailed excess generations) and backing up the microgrid during the peak hours (and hence avoiding overbuilt infrastructure). Distinct grid power prices (charged by the utility for energy purchased from the grid) and sellback rates (paid by the utility for power sold back to the grid).
	Network charges	Volume-related charges and demand charges on imports available from network tariffs.
Calculating microgrid infrastructure costs	Network lease costs	Recommended to be considered as a sensitivity variable because of the potentially significant uncertainties involved in its estimated value and future changes in its valuation.
	Costs associated with the internal controller and operational exercises	The costs of controllers can be considered as fixed capital costs, while the estimated yearly costs to supervise the operation of the microgrid can be considered as fixed operational costs which are then discounted in the cash flow.
Evaluating the impact of the microgrid on energy bills	Current energy charges	Typical charges for residential energy can be obtained from government sites, while large business tariffs are more complex.
	Consumer profiles	As with load, consumer profiles can be obtained from smart meter data (with customer permission) or from consumer monitoring devices such as the Wattwatchers devices. For volume charges, average consumption can be obtained by area from government energy sites.[15]
	Feed-in-tariff	The current and future value of any feed in tariffs, and their applicability, needs to be determined to calculate current energy bills.
Operational constraints	Operating reserve	The amount of operating reserve the system needs to be able to provide each hour.
	Sale and purchase capacities	The variables describing the microgrid's capacity to deliver and accept power. The maximum grid demand (i.e., the maximum amount of power that can be drawn from the grid) can be considered as a decision variable because of the effect of demand charges.
Future costs and needs	Future load profiles	In order to undertake a detailed assessment of the cost effectiveness of a microgrid over 25 years, future demand and costs should be included (this has not been done at this stage in the project). Conditions are expected to change quite significantly; for example, feed-in-tariffs declining for solar PV over time, load increasing with electric vehicle as adoption grows, battery costs declining.
	Future CAPEX	
	Future energy charges and buyback rates	

3.3 Spatial data

An early task of the microgrid modelling was to identify the boundary of the electricity network that would be modelled and match it with other data sources to understand the drivers of energy consumption within the boundary. AusNet Services provided spatial files which built on the publicly available map of the Medium Voltage distribution system[m]. Detail about the data provision is in *Data supply and choosing the right tools*. For identifying the boundary, the project team needed to know:

- All loads on the Heyfield feeder (MFA 34, shown in orange in Figure 7)

[m] https://dapr.ausnetservices.com.au/

- Possible points of disconnection, for example switches, preferably switches that could be automated.

The boundary chosen for modelling (Boundary 3) is shown in Figure 7, and the different boundaries considered are shown in Figure 3 .

AusNet Services also provided the location of distribution substations throughout the area. Each substation supplies electricity to at least one customer so the number identified inside and outside the boundary supported the estimates of customer numbers and load types.

Australian Bureau of Statistics (ABS)[n] data was used to estimate household numbers and the level of commercial and industrial energy use that could be anticipated. The ABS data also supports estimates about the number of farms still operating as dairy farms, and the household energy consumption survey from 2014 gives some characterisation of residential energy loads. Figure 4 shows the allocation of loads and customers across various parts of the boundary.

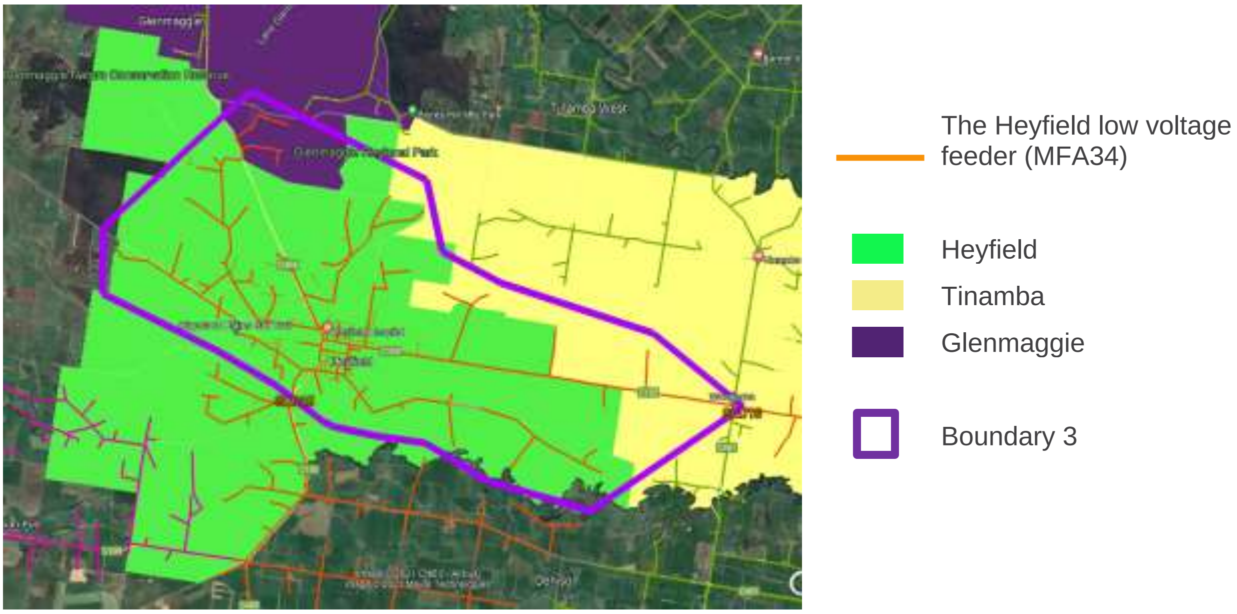


Figure 4 Heyfield ABS boundaries compared to Boundary 3

[n] The smallest boundary in ABS data is the State Suburb Classification (SSC) which approximately correspond to the localities and suburb names used by other authorities such as State and Local governments.

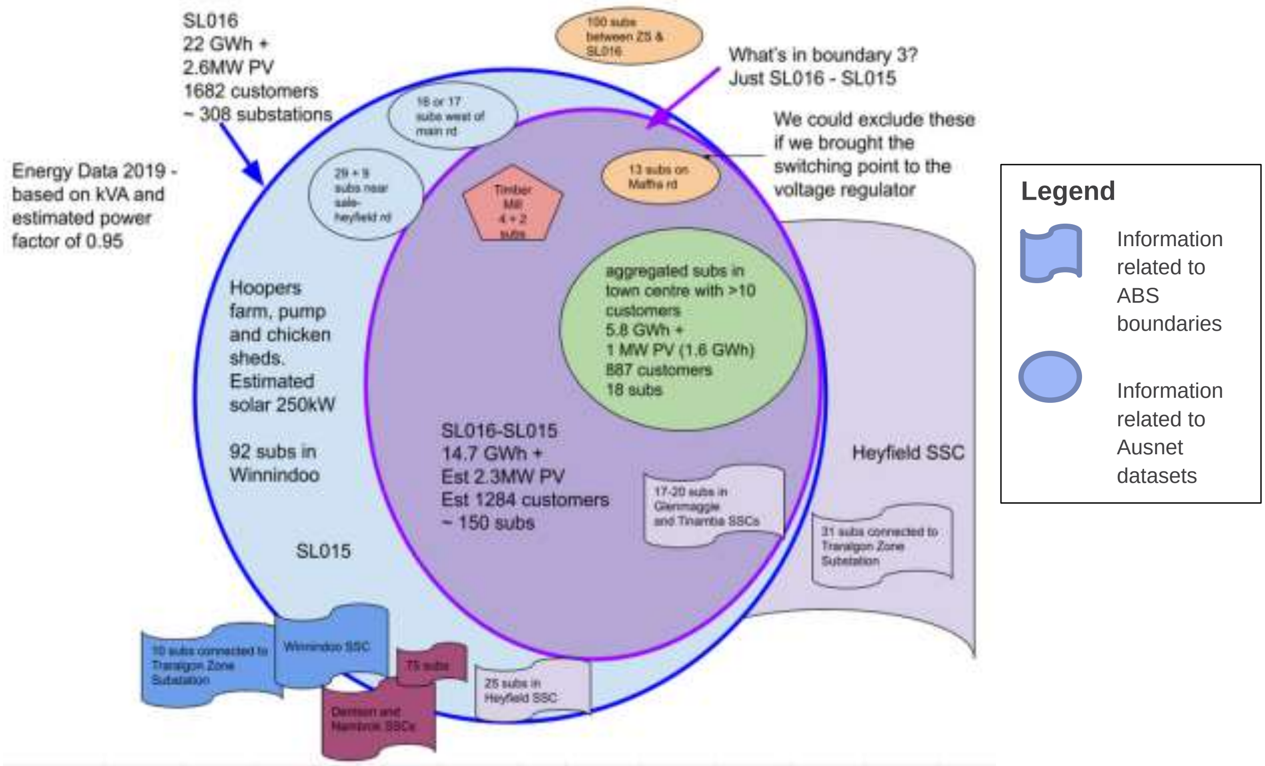


Figure 5 Synthesis between ABS data and boundaries defined by different Ausnet datasets

3.4 Later versions

For this initial analysis, we did not have sufficient length of data from Wattwatchers devices (12 months) to derive typical load profiles which could then be scaled up in accordance with the number of households within Boundary 3. It was not possible to estimate the sub-loads (e.g., hot water cylinders) associated with each load profile, as sufficient contextual information was lacking at the time this analysis started.

This project has yielded valuable learning in regard to data sources and availability, including the timing and approach to installing consumer-side monitoring devices such as Wattwatchers, and the parallel capture of detailed contextual information at sites. While ultimately this data was not required in order to assess feasibility for a full microgrid, because other higher-level factors outweighed such detailed bottom-up analysis, the datasets and associated analytics now being assembled for Heyfield are highly relevant for any further microgrid feasibility consideration, and for assessing alternative local energy solutions that can help step the town towards a more engaged and independent energy future.

If it is decided that further investigation of the microgrid option should be carried out, the overall load in Boundary 3 will be synthesised based on deriving typical profiles and upscaling. Ideally, this would also be cross referenced with smart meter data, in order to determine the minimum number of devices needed to approximate the total load.

Simulations could then be re-run using the synthesised load demand profile with the results benchmarked against those obtained based on the SCADA data and other top-down data sources.

Such a bottom-up approach could enable investigating the “least data” path for replication in terms of the minimum data requirements (including the minimum number of Wattwatchers devices required) to produce the load scenarios and their relative importance on the pre-feasibility results. Minimum data is only useful with additional contextual information (e.g., provided via Ecologic surveys or by additional information capture during device installation). This additional information is needed to verify load and equipment correlation and to identify potential skews toward particular customer types. These types of synthesised load profiles will be needed for testing most local energy options, so this analysis is likely to be undertaken whichever path the future analysis takes.

4 Is a town microgrid technically feasible?

4.1 Modelling the technical feasibility

This task aimed to model the technical feasibility of a microgrid in Heyfield to answer a number of questions:

- How much local renewable generation could a microgrid support, and what are the limits on export and import?
- What additional control infrastructure (if any) would be needed at different penetrations of local renewable generation, and what would the associated costs?
- What are the impacts of local generation capacity and connection on the reliability of the system?
- What is the impact of different network topologies?
- What is the impact of storage, and what would it cost?

The microgrid was modelled using various combinations of data as shown in *Figure 6*. The medium voltage (MV) network and distribution substation locations are adopted from the PSS SINCAL model provided by AusNet Services. The distribution transformers' kVA ratings are estimated based on the substations' statistical load data. Each distribution substation has been modelled as combined load, solar PV, storage, and synchronous generators, which can be easily connected/disconnected to create different scenarios for the integration of distributed energy resources (DERs).
It was observed that the incoming supply feeder from the Maffra zone-substation to this area, which would connect to a microgrid at open point A on Figure 3, has a significant impact on the network and user voltage. This feeder plays a key role in determining the load and generation hosting capacity in the grid-connected mode. To capture the temporal dynamics of this incoming feeder, Boundary 3 has been modelled with incoming feeder parameters.

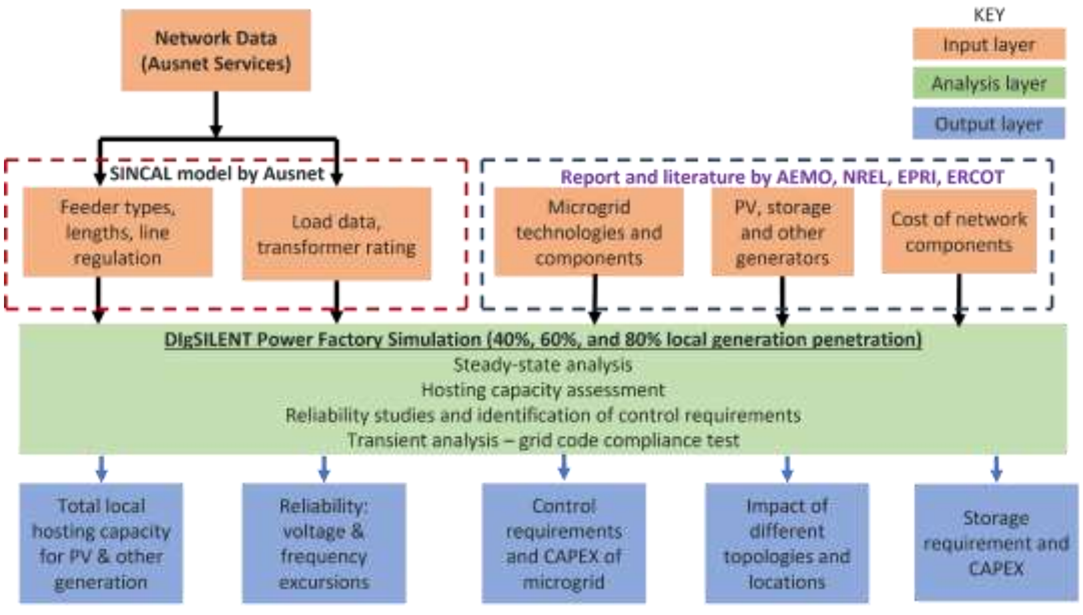


Figure 6 - Modelling approach.

The technical analysis has been conducted using the DIgSILENT Power Factory, a leading power system analysis software application for use in analysing generation, transmission, distribution, and industrial systems (e.g., mines, wastewater treatment plants). Various tools are available for such studies. However, DIgSILENT provides flexibility to model both conventional and power electronics-based systems with high accuracy. It also offers a wide range of analytical toolboxes, including steady-state analysis, dynamic stability analysis, reliability assessment, time series analysis, power quality, techno-economic analysis, and others.

6.1.1 Network Steady-State Performance Assessment

Network steady-state performance analysis is conducted to find the amount of DERs that can be added to a distribution system before control changes or system upgrades are required to safely and reliably integrate additional DERs. It should be emphasised that this capacity does not represent a hard limit on the amount of DERs that can be added to the distribution system and can be increased by upgrading control or other elements. As upgrades are implemented, the more hosting of local generation is possible.

A performance index is used to determine the level of possible generation or load accommodation prior to upgrading before a defined constraint (such as a limit on frequency fluctuation) is violated. This index can correlate with voltage constraint violation, loading violation, protection setup etc., and can be interpreted as the system robustness. Therefore, the local generation penetration capacity can also be defined as the amount of new generation or consumption where the performance index reaches its limit.

In this assessment, each node is modelled individually. A virtual generator is internally connected to the first terminal from the hosting sites selection. Beginning from the initial power value, the power of this generator is scaled until one of the user-defined constraints is violated. The analysis then continues with the next node until all hosting sites are modelled and examined.

6.1.2 Quasi Dynamic Analysis

The load flow calculation for the network model is undertaken in DIgSILENT Power Factory and considers a single set of operating condition (that is, it is undertaken as a snapshot at a single moment, rather than the time series data of hourly or half-hourly intervals for the entire day, month, or year). In most electrical systems, engineers are interested in the system's performance during worst-case operational conditions. However, due to the complexity of the network, it might be difficult to intuitively understand which operating scenarios and network states cause such conditions. Consequently, to determine the worst-case operating conditions, engineers must often run several load-flow simulations with a range of different operating conditions. This is usually achieved by modelling the network at a series of different timescales because most operational parameters have an inherent dependence on the timescale of interest. For example:

- Load is dependent on time, day, and month due to daily and seasonal cyclic load variations.
- Non-dispatchable renewable sources (such as wind and solar) vary with the weather and season.
- Network variations, maintenance outages, faults, and unscheduled outages normally have some time dependence.
- Equipment ratings can also change due to the effects of wind and temperature.

In this context, a reasonable and pragmatic approach is to simulate the so-called “Quasi-Dynamic” phenomena using a series of load-flow calculations with various model parameters being time-dependent.

6.1.3 Reliability Analysis

The reliability analysis of a microgrid represents the service availability to the microgrid community. The reliability of the system as it stands is influenced by the (un)availability of the supply feeder and various equipment outages. However, data is not available for the general reliability performance of the supply feeder, nor for emergency situations such as bushfires.

We have therefore only been able to compare the reliability of the network within the microgrid and immediate supply line (the feeder to the Maffra Sub Station) in the grid connected and islanded mode, including any additional infrastructure required. This analysis is given in *Appendix A Technical feasibility – reliability analysis.*

6.1.4 Economic assessment – system upgrade

In this analysis, the system upgrade costs, including the upgrade of the distribution system capacity (the lines and transformers) and the control equipment (e.g., voltage regulator) are considered. Upgrade deferral/deferral benefits could not be assessed due to the snapshot nature of the analysis used for this study, so care should be taken when comparing these results with other similar work. Details of the capital expenditure derivation and the values used are given in *Appendix B Technical feasibility – capital expenditure inputs.*

4.2 Results – technical feasibility

This section explains the technical study results for Boundary 3 (Heyfield Town). The following two scenarios were considered:

- Scenario 1 – Boundary 3 (without the Australian Sustainable Hardwoods (ASH) load and without the bioenergy generation). This scenario is to test the microgrid without the integration of the timber bioenergy generator; of course, ASH may still install a bioenergy generator, but it is assumed to operate independently from the microgrid, primarily to meet its own load.
- Scenario 2 – Boundary 3 (with the Australian Sustainable Hardwoods (ASH) timber manufacturer load and bioenergy generation). This scenario includes ASH load and assumes a 2 MW bioenergy generator to be installed and entirely integrated with the microgrid operation. The timber manufacturer is assumed to share generation locally in this scenario and operate the bioenergy facility as benefits the microgrid.

For quasi-dynamic simulations and reliability analyses, different DER penetrations (40%, 60%, and 80%) local generation were considered to evaluate the relative impact on network performance. In addition, different voltage controls via PV inverters, voltage regulators, and batteries were considered to improve the hosting capacity and network performance. It should be noted that the grid code compliance test[o] was not considered at this stage, as this is unlikely to have affected the initial economic analysis.

In each scenario, the technical feasibility has considered two pathways to reach the higher penetrations of local generation (at 40% of local generation, no further installation is needed – current DER penetration in Boundary 3 is at 40%). *Table 2* summarises the required generation and storage equipment by scenario.

Table 2 MW of generation and storage equipment by scenario

Scenario	**Equipment**	**Local generation**			
		Unit	**40%**	**60%**	**80%**
Scenario 1 (excluding the timber manufacturer), mainly rooftop PV	Rooftop PV	MW	2.7	3.1	3.80
	Centralised PV	MW	-	-	-
	Bioenergy	MW	-	-	-
	Storage	MW)	1.0	1.0	1.0
Scenario 1 (excluding the timber manufacturer), mainly centralised PV	Rooftop PV	MW	2.7	2.6	3.0
	Centralised PV	MW	-	0.5	1.0
	Bioenergy	MW	-	-	-
	Storage	MW	1.0	1.0	1.0

[o] Grid codes specify the electrical performance that generation assets must comply with in order to obtain the required approval for connection to a grid. Demonstrating grid code compliance and achieving a grid connection agreement are, therefore, essential milestones in the development of a DER project. Grid code compliance verification shall include revision of documentation covering technical data and models, checking of requested capabilities, and validation of model performance. Static and dynamic simulations are needed for operational, planning, interconnection, and plant design purposes.

Scenario	Equipment	Local generation			
		Unit	40%	60%	80%
Scenario 2 (including the timber manufacturer), mainly rooftop	Rooftop PV	MW	2.7	3.3	4.0
	Centralised PV	MW	-	-	-
	Bioenergy	MW	-	2	2
	Storage	MW	0.5	0.5	0.5
Scenario 2 (including the timber manufacturer), mainly centralised PV	Rooftop PV	MW	2.7	2.7	2.7
	Centralised PV	MW	-	0.5	1.5
	Bioenergy	MW	-	2	2
	Storage	MW	0.5	0.5	0.5

6.2.1 DER Penetration Limits

summarises the amount of DER for different terminals without network augmentation. This has been calculated for each terminal considering voltage and thermal limits. The study also assessed the limiting component in the network governing the hosting capacity of the DERs. From the table, it is evident that the penetration limit of most of the terminals in the network range from 0.93 MW to 4.66 MW, depending on the reactive power control approach (e.g., volt/Var control and changing load tap position) used in the system. There are a number of terminals at the edge of the Heyfield grid which show a lower capability to host the DER, in the range of 0.93 to 2.43 MW. Moreover, the terminals that are located close to the town centre have a higher DER accommodating capacity than the terminals at the far end of the network (see Figure 7). The high hosting terminals are located along the main feeder connecting Heyfield to the MFA Substation. Note that this estimation is for the terminal itself, and thermal limits also apply to the combined export, so the amount that could realistically be installed at any point without augmentation will be impacted by what is installed downstream and upstream. The total penetration limits of DER in the network against the voltage limits are estimated and found be 11.8 MW (no limit to export to the external is considered).

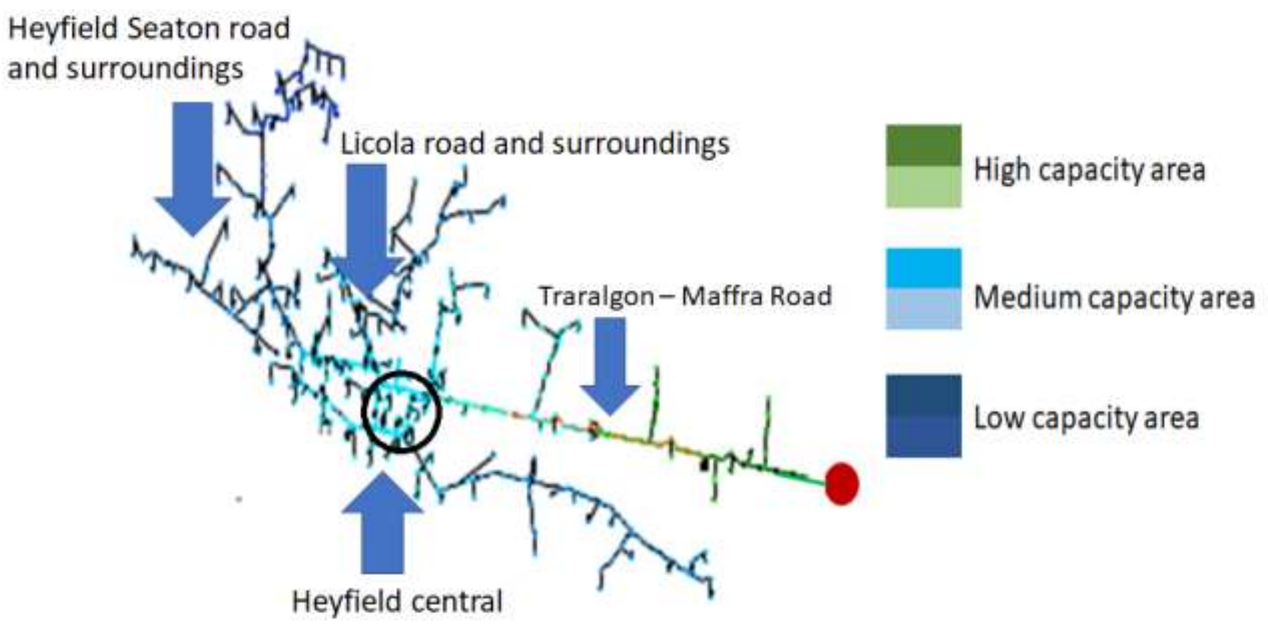


Figure 7 - Heyfield network with different capacity limits

Table 3 Summary of DER hosting

Terminals	Maximum active power (MW)	Number of terminals
High-capacity terminals	3.25 – 4.66 MW	56 (Terminals at the main backbone feeder connecting Heyfield to the MFA)
Medium capacity terminals	2.56 – 3.2 MW	97 (Terminals around the Heyfield town centre)
Low-capacity terminals	0.93 – 2.43 MW	147 (Terminals at the far end of the Heyfield network)

Table 4 presents the export limits to the grid and the corresponding voltage limits[p]. From the table, the maximum active power export of 1.68 MW was observed without violating the voltage limits set by the DNSPs.

Table 4 Different export and voltage limits

Voltage limits (pu)	Maximum export power (MW)
1.01	1.40
1.02	1.50
1.04	1.60
1.05	1.68
1.07	1.70
1.10	1.80
1.15	2.00
1.16	2.20

Limit outside acceptable range   Limit within acceptable range

[p] The threshold (0.94 pu-1.06 pu) used by all Australian DNSPs was used for the assessment.

6.2.2 Quasi Dynamic Performance

Figure 8 - Voltage profiles at (a) 40%; (b) 60%; and (c) 80% local generation.

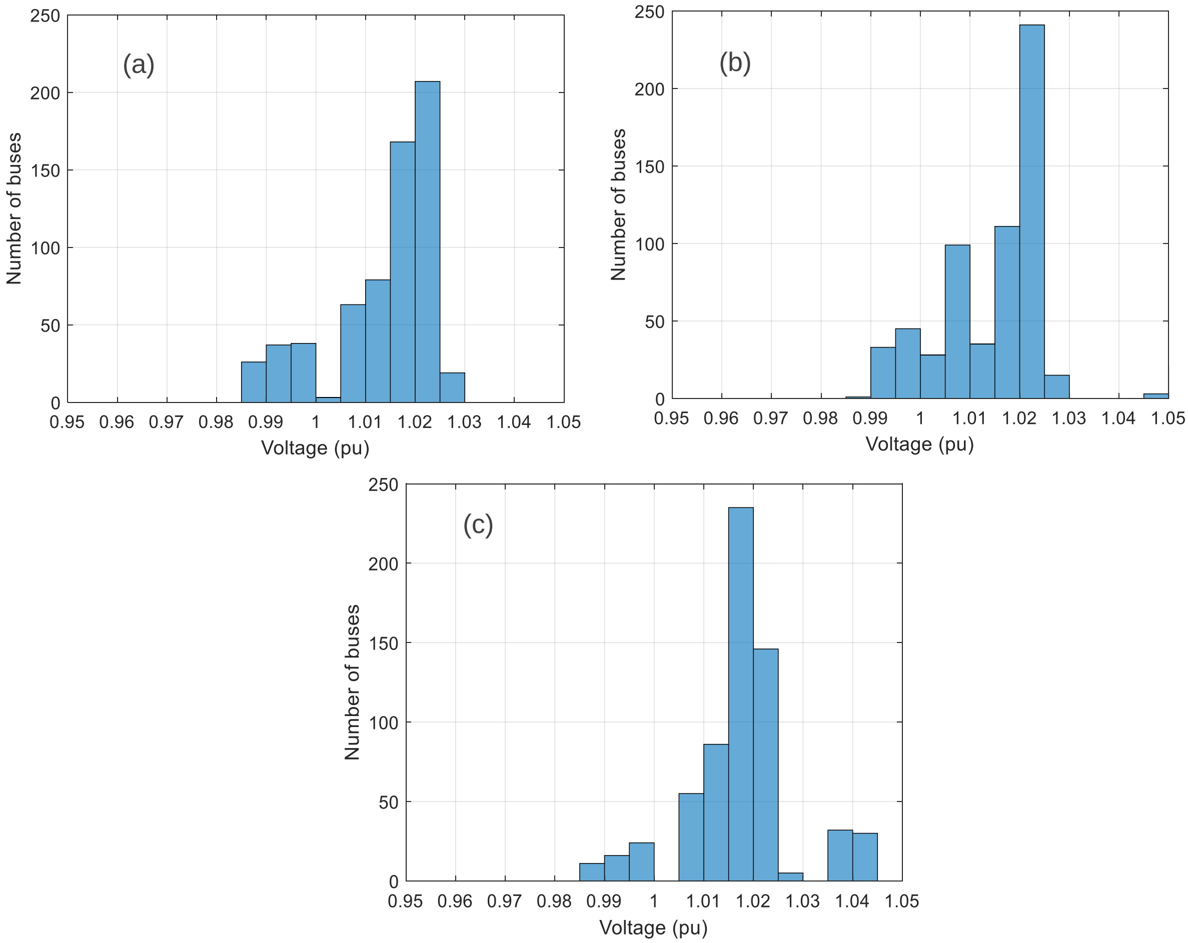


Figure 8 shows histograms of the voltage profiles obtained through the quasi-dynamic simulations for Scenarios 1 and 2 at different penetration levels of local renewable power generation. The simulations were conducted for a representative 24-hour period and the envelope of the voltage profiles were recorded to examine the voltage variations in the network. The threshold (0.94 pu-1.06 pu) used by all Australian DNSPs was used for the assessment.

In Scenario 2, the network does not experience any over- and under-voltage issues due to the presence of a dispatchable generator in the system. In scenario 1, however, minor over-voltage occurrences were observed in the network during the periods of light-load for the case that integrates a high PV generation capacity with relatively low battery storage capacity. It is expected that such over-voltage occurrences could be addressed by considering optimally sized batteries and utilisation of Volt/Var control.

It is worth noting that the potential microgrid could operate in either scenario without compromising voltage limits.

6.2.4 Cost of microgrid establishment

Table 5 summarises the CAPEX and OPEX required for different local generation penetrations. A detailed list of CAPEX by scenario is included in *Appendix B Technical feasibility – capital expenditure inputs*. This does not include the connection costs for centralised generation or batteries, as these have been included with those technologies (for example, the transformers associated with the bioenergy or the centralised PV generators are included in their respective CAPEX).

From the results given in Table 5, it is evident that the CAPEX for different scenarios does not vary very much, from $0.27 m to $0.56m. The lowest CAPEX was observed for scenario 2 (bioenergy and rooftop PV) under all renewable penetrations. From the results presented in Table 7, it can be observed that a higher CAPEX is required for scenarios with centralised PV generation due to the costs of collector systems, large (i.e., MW level) transformer, and project devices. Flat-rate operation costs are considered for the transformer and other electrical maintenance[7], so the OPEX remains the same for all scenarios and at all renewable penetrations. This section only deals with the CAPEX and OPEX specifically associated with the network elements of the microgrid; those elements associated with generation are covered in the economic modelling. A breakdown of what is included in this summary is given in *Appendix B Technical feasibility – capital expenditure inputs*, while CAPEX and OPEX associated with generation is given in *Appendix C Inputs and assumptions for economic modelling*

Table 5 Summary of CAPEX and OPEX for microgrid infrastructure (not including generation and storage)

Scenario	DER type	40% penetration	60% penetration	80% penetration
Scenario 1 (CAPEX)	Distributed rooftop PV	$0.59m	$0.59m	$0.62m
	Centralised large PV	$0.59m	$0.63m	$0.94m
Scenario 2 (CAPEX)	Distributed rooftop PV + ASH bioenergy	$0.59m	$0.60m	$0.62m
	Centralised large PV + ASH bioenergy	$0.59m	$0.35m[q]	$0.35m[q]
Scenario 1 and 2 (OPEX)	All DER types	$43,750	$43,750	$43,750

4.3 Technical feasibility - conclusion

The technical feasibility study aimed to produce indicative results to help identify whether a microgrid solution is worth more detailed analyses. To this end, the study examined the hosting capacity of a potential microgrid, the associated OPEX and CAPEX outlay, the reliability implications for consumers, the relative importance of the network topology, and the potential value of the integration of battery storage. The summary findings are as follows:

1) Overall technical feasibility and DER hosting

The current MV systems of Heyfield are capable of supporting a microgrid to supply a load well above the current peak load of the network and can host sufficient DER (i.e., PV and other local generation) capacities to reach more than 80% of local generation.

- The MV supply feeders are the main limiting factors in the hosting capacity of load and local generation. They also influence the export limit from the Heyfield network to the wider utility network.

2) Requirements and costs for microgrid infrastructure

Various microgrid network components such as voltage regulators, transformers, load tap changers' (LTC) set point change, and HV voltage switchgear would be required to develop a microgrid in Heyfield. The CAPEX outlay associated with the network components for different scenarios have been identified.

The system model with the timber manufacturer (i.e., including bioenergy generation) and rooftop-PV shows lower CAPEX compared to the system without bioenergy. Both centralised and rooftop-PV are likely to require higher CAPEX.

The network OPEX is based on fixed costs for the transformer and other electrical equipment maintenance. It is expected to remain constant across the different scenarios.

[q] The CAPEX appears lower in the scenarios with centralised PV as some of voltage regulation is now supplied by the new transformers associated with the new generators

These cost estimations will be used to inform the techno-economic modelling of the microgrid and provide a first estimation of the costs for the microgrid infrastructure.

3) Reliability

The SAIDI, SAIFI, and ENS indices, which measure outages and unserved energy, all decrease somewhat (i.e., system reliability is increased) with the higher local generation capacity.

System reliability is increased in the islanded mode compared to the grid-connected mode. However, higher CAPEX is needed to increase the system reliability.

The models and framework that have been developed can be used to assess the impact of an islanded microgrid on all aspects of the stability (voltage and frequency) for a weak power grid.

See Appendix A for more details of the reliability analysis.

4) The impact of different technologies

The voltages across the network in different operation modes were more consistent due to the voltage support of the backup generator. However, minor over-voltage was observed in low load and high PV penetration (with low penetration of storage) scenarios. Such minor over-voltage issues could be addressed by considering additional batteries in the network.

5) Storage requirements

Community battery storage capacities of 0.5 MW to 1 MW have been considered in the initial technical study. The optimal size of the storage was determined based on the coherent equipment capacity planning optimisation carried out in the economic modelling (See Section 8).

Further steady-state and dynamic simulations of the network could be conducted with the optimal storage capacity determined from the associated optimal sizing studies.

5 Is a town microgrid feasible from a regulatory perspective?

5.1 Key questions for regulatory feasibility

The regulatory frameworks for the electricity industry are premised on the administrative and legal separation of these aspects of an electricity system. In other words, the regulatory framework requires that different legal entities operate the network and generation/retail aspects. Only narrow exemptions apply, and different rules apply to these separate activities involved in the operation of a microgrid. Proponents will need to consider who should own and operate the various aspects of the microgrid and which rules apply to these entities. In particular, the following questions should be considered:

- Who will own and operate the physical microgrid network assets, including ensuring reliability, and balancing load and supply?
- What arrangements will be needed to take control of the network assets, i.e., by purchasing or leasing from the current owner, and what are the limitations on how this can be done?
- Who will operate the financial (retail) side, and what are the limitations?

This section sets out an introduction to the applicable regulatory frameworks and introduces key rules to help proponents consider these questions.

5.2 Background – introduction to regulatory frameworks

The electricity sector is an essential service and, therefore, tightly regulated to guarantee supply to the consumer. The production, transport and sale of electricity is subject to a number of regulatory frameworks at state and national levels. The most important of these include the requirements of:

- The Electricity Industry Act 2000 (Vic) (EIA) and associated regulations (in particular, the General Exemption Order 2017 (GEO), the Energy Retail Code, and the Electricity Distribution Code).
- The National Electricity Victoria Act 2005 (Vic) (NEVA), and
- The National Electricity Law (NEL) and National Electricity Rules (NER).

The EIA sets up a licencing and exemption regime. It prohibits any activities without a licence. Section 16 of the EIA expressly states that:

> (1) A person must not engage in the generation of electricity for supply or sale or the transmission, distribution, supply, or sale of electricity unless the person
>
> (a) is the holder of a licence authorising the relevant activity; or
>
> (b) is exempted from the requirement to obtain a licence in respect of the relevant activity.

Licences are granted by the Essential Services Commission. There is an exemption regime which applies under certain conditions. Separate rules for distribution, generation and retail licences apply, but generally the Essential Services Commission requires a licence applicant to demonstrate that

- They are a fit and proper person to hold a licence
- They have sufficient technical capacity to comply with their licence conditions, including the capacity to operate and manage the relevant business, and comply with applicable regulatory requirements
- They are financially viable and have sufficient financial resources to establish a sustainable business able to satisfy the interests of consumers.[r]

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[r] See ESC website, https://www.esc.vic.gov.au/electricity-and-gas/electricity-and-gas-licences-and-exemptions/electricity-and-gas-licences

In addition, where the microgrid is connected to the National Electricity Market, the NER and the NEVA apply. Market participants need to be registered with the Australian Energy Market Operator (AEMO).

The degree to which these regulatory regimes apply depend on the size, complexity and assets integrated in the microgrid.

Please note that a number of reforms are currently underway which may impact these rules and regulations (see *Business Model Scan & Market and Regulatory Review*[16]).

5.3 Key regulatory issues for operating the microgrid network

The local distribution grid is currently owned and operated by the local Distribution Network Service Provider (DNSP), in this case AusNet Services. Proponents of a microgrid have several options on how to establish and manage the actual grid. These are:

- Option 1: Procure the local grid and all its related assets from AusNet Services.
- Option 2: Lease the local grid and all its assets from AusNet Services.
- Option 3: Negotiate with AusNet Services to establish and operate a microgrid on the community's behalf.

Table 6 Summary of network control and operation options

Control of microgrid	License requirements	Network operation	Comment
Option 1 Purchase network from AusNet Services	Requires license to operate network unless exemption applies under the GEO. This can be achieved either by contracting a licensed entity, such as AusNet to operate the network or by seeking a licence or an exemption	AusNet Services or other licensed entity	See below, exemption requirements are not fulfilled in this case
Option 2 Lease network from AusNet Services			
Option 3 Network control remains with AusNet Services	AusNet Services is licensed	AusNet Services	Only likely if this will achieve a cost saving for network operation, but recommend investigating with AusNet Services

Leaving aside the costs of buying or leasing the network, options one or two will require a licenced entity to operate the grid. This means that the proponents would have to become a licensed network service providers or engage a licenced provider.

Options 1 and 2 will trigger the need to get a licence under the Victorian regulatory frameworks of the EIA. Apart from the general conditions set out above, licence conditions include the adherence to the Electricity Distribution Code.[s] This requires the DNSP to provide a large range of ongoing services, including maintenance of equipment and good asset management, managing of connections and disconnections, guaranteeing quality and reliability of supply, meeting guaranteed service levels, managing complaints and others. Any community should carefully consider whether they can provide this level of ongoing commitment. Exemptions to these requirements can be granted to small private networks. There are deemed exemptions for networks supplying to fewer than 10 customers, which would not be applicable in a town microgrid situation (see GEO section 6). Registrable exemptions are available for supply within sites owned, occupied, or operated by the person seeking the exemption. In other words, network infrastructure crossing property lines usually excludes the availability of an exemption. Examples where exemptions may apply are embedded networks in apartment blocks, caravan parks or retirement villages (see GEO section 7). Please note that a multiple activity exemption is also available and discussed below in 6.5.

[s] Version 13 (July 2021)

In addition, operating an electricity network connected to the shared grid requires registration with AEMO, unless an exemption applies.[t] A microgrid of the scale planned here would not fall under any current exemption categories under the NEM frameworks.

Alternatively, the current DNSP may agree to operate the microgrid. Generally speaking, the DNSP would only have an incentive to do so if it were more cost-effective than centralised provision. An indicator for this being the case may be where the DNSP is regularly not meeting guaranteed service levels. However, a more detailed conversation with the current DNSP could help to identify available options. There is a push to enable stand-alone power systems managed by the DNSP, but the changes have been made for systems not connected to the interconnected national electricity system. If the microgrid is an embedded network[u] further regulations apply both on the NEM level and for Victoria specifically. Further reforms are underway and may influence the opportunities available here.

5.4 Key regulatory issues for retail aspects of the microgrid

Energy retail also needs a licence under the EIA, unless an exemption applies. The exemptions available are similar to those set out above for the distribution licence exemption and are unlikely to apply to the scale or scope of a town microgrid. Please note that a multiple activity exemption may also be available and discussed below in 6.5.

The Victorian Energy Retail Code[v] applies, and with this a range of conditions to set up around retail administration, contract management, compliance, billing and so on. Generally speaking, retail competition needs to be maintained. This means that consumers cannot be forced to join the retail offer by the microgrid retailer and must retain the option of leaving the arrangements. The Victorian Default offer, set by the Essential Services Commission, provides the maximum price for consumers in embedded networks. An exemption from retail licence requirements is only available for selling to a small number of customers usually with the limits of a single site, which does not apply to the situation in Heyfield.

In any case, a regulator or Government would be unlikely to grant bespoke licencing or exemption framework that limits access to competition unless they are assured no person will be 'worse off' now or into the future. This is likely to mean energy charges would be no higher than the best available market offers and may mean equivalent access to other energy services and products, such as solar PV feed-in tariffs and electric vehicle charging, would be guaranteed. Meeting these requirements would impose material risks and constraints on any project that removes access to competition.

5.5 Regulatory feasibility of generation aspects of the microgrid

Generators within the microgrid may require a generation licence under Victorian regulations and will have to register with AEMO if they would like to export to the NEM.

Deemed generation exemptions from licence requirements under the GEO are available for "persons generating electricity for supply or sale where the total output by that person (whether or not with another person), using a generator connected to the transmission network or distribution network **at a common point** is **less than 30 MW**" (GEO Part 3 Section 13).

Selling of energy from a variety of generation sources in the microgrid to the wholesale market could be achieved with the help of a small generation aggregator, registered with AEMO.

5.6 Multiple Activity Exemption

Please note that proponents could consider registering a multiple activity exemption under the GEO (section 17). This exemption is available for projects that have distribution, retail, and generation aspects. However,

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[t] A detailed exemption guideline is provided here https://www.aer.gov.au/system/files/AER%20electricity%20NSP%20Registration%20Exemption%20Guideline%20-%20Version%206%20-%201%20March%202018.pdf

[u] AER defines that "*an embedded network is formed when a 'parent' or 'gate' meter is placed between meters of multiple customers and the poles and wires that form part of the national grid*."

[v] Version 21 (July 2021)

here again, a number of conditions apply, including the price ceiling provided by the retail default offer, maximum name-plate capacity of 5 MW generation, selling of output to a licenced retailer, application of the Australian consumer law and compliance with specific sections in the distribution code.

This exemption is unlikely to apply as total name-plate generation capacity must be no more than 5 MW. The total generation capacity in Heyfield is estimated to be between 8 MW and 12 MW (see Section 8).

We would recommend that advice on the applicability for this exemption is sought from the Essential Services Commission, even if the total name-plate capacity is under 5 MW, as the scope of this exemption is unclear.

For a microgrid with a connection to the NEM, additional requirements apply. Generation systems with a name-plate rating of 5 MW or less connected to the distribution system have an automatic exemption according to AEMO guidelines.[w] However, a microgrid may fall under the embedded network definition if there is only one parent connection point to the shared distribution or transmission network. In this case, for an automatic exemption, all generating systems in this network need to have a combined total nameplate rating of less than 5 MW. In other words, the project proponents need to add up all the generation capacity within the microgrid.

5.7 Regulatory feasibility of the microgrid – conclusion

At this stage, the establishment and operation of a town-sized microgrid is an extremely complicated undertaking. Regulatory frameworks are slow to change to accommodate more flexible business models that are not premised on the strict separation of network operation from generation and retail. In particular, the proponent would be required to:

- Hold a license to operate an electricity distribution network, or an exemption from the need to have a license, except in the case a licensed entity is engaged to operate the network (noting that automatic exemption for an embedded network does not apply as the network crosses property boundaries).
- Hold a generation license or an exemption from the need for one (noting that automatic exemption may not apply).
- Hold an electricity retail license unless or an exemption from the need for one (noting that automatic exemption is unlikely to apply, it is recommended to engage a licensed entity for the retailing aspects).
- Be able to ensure that consumer protection laws are maintained, which generally means that consumers must retain the option to leave the microgrid retail arrangements.
- Ensure that consumers will not be paying more for their electricity under microgrid arrangements than equivalent energy market offers, and potentially ensure consumers have equivalent access to other energy products and services.

Proponents should carefully consider whether the potential gains from the microgrid outweigh the risks and administrative effort associated with meeting licencing conditions and other regulations. While the regulatory feasibility of a microgrid for Heyfield is not clear cut, a microgrid not involving the distribution network service provider (DNSP) AusNet Services is likely to be unfeasible owing to the high expense of, and barriers to, regulatory compliance. Proponents would need to undertake protracted negotiations and may still find that the regulator would not accept the case, particularly in the absence of clear benefit for consumers. There may be options to partner with the DNSP to provide a service which could facilitate local use and trading of renewable energy while maintaining the existing grid arrangements, although with bespoke network tariffs.

This overview does not constitute legal advice. Specific business model proposals should be assessed by a qualified lawyer to ensure all conditions are met.

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[w] See section 3 of the AEMO, Guide to Generator Exemptions and Classification of Generating Units (October 2021).

6 Is a town microgrid economically viable?

6.1 Modelling the economic feasibility and stakeholder outputs

The economic feasibility of the microgrid was investigated using HOMER software, which is a distributed energy optimisation model. The optimisation process finds the system configuration that gives the lowest total discounted system cost, using the candidate technologies and within any specified constraints.

The optimal system configuration includes the size and combination of components (for example, generation technologies) that the microgrid should contain, and the "dispatch strategy." The dispatch strategy specifies when dispatchable plant (in this case, bioenergy and batteries) should be operated and this governs energy exchanges with the wider utility grid. The constraints dictate aspects such as the amount of energy that may be imported and exported, with the optimisation aimed at finding the least-cost solution. In addition to finding the optimal system configuration under a particular set of input assumptions, sensitivity analyses were undertaken to show the robustness of the outputs to changes in the key inputs, such as the cost of the bioenergy fuel.

There are a number of key indicators that HOMER is unable to calculate directly, which were calculated in Excel using HOMER outputs:

- **Levelised cost of energy (LCOE)**: this was calculated using the net present costs directly from HOMER divided by the discounted energy delivered, with the discounting performed externally[x].
- **AusNet Services income**: this is calculated outside the HOMER model. The network lease cost (a model input) was added to demand[y] and volume[z] charges calculated by using the model outputs for peak load and energy purchased from the grid and the appropriate network tariff.
- **Residential bills**: for non-solar households are calculated using the LCOE for each scenario as the volume charge, plus a standing charge of $111 per year. Average consumption for Heyfield is taken from the Victorian government site for energy bill comparison[17]. Average bills are also calculated for solar households, assuming a 4 KW installation with 30% of output self-consumption, and a feed in tariff (FIT) of 4 c/kWh for exports in the non-microgrid (baseline) case.

6.2 Modelling the load

AusNet Services provided SCADA data and aggregated data compiled from the smart meters in the area. Both provided 15-minute data across 2019 and 2020, with 2020 used as the baseline year.

The time series SCADA data has been provided at two switches – SL016 and SL015. The load that a microgrid for boundary 3 would need to serve is calculated by deducting SL015 from SL016. There were a number of outages documented. For use in HOMER modelling, these times were backfilled with representative load.

Aggregated data was used to cross check load in subsets of the boundary, supporting a bottom-up analysis to ensure that load across the region had been identified, by understanding both the types of customers and the likely use (e.g., heating, cooling, lighting, hot water, cooking, and other appliance use). Several data

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[x] The LCOE calculated in HOMER uses a non-standard definition (NPV divided by the undiscounted energy delivered). This gives a systematically lower LCOE, making comparison with other sources problematic.

[y] The network tariffs are an input to the model. Total demand charges were calculated by multiplying both the critical peak and capacity network tariff rates by the peak import observed from the output time-series data (the peak was in fact the import limit in each case). In order to also include them in the LCOE, we first ran the model without demand charges. Then, based on the peak import identified from the modelling results, the corresponding demand charges were calculated outside the model and added to the fixed O&M costs to re-run the model and find the LCOE.

[z] Network volume charges included in the time series on energy import costs. It was assumed that in general imports would correspond with peak times because of the high penetration of solar, so the volume charges were estimated by using a combined peak/ off-peak rate calculated by apportioning only the number of off-peak days to the off-peak rate. The combined tariff was set as [105/365 x off-peak rate] + [260/365 x peak rate]

sources were used to develop this load breakdown (see the milestone report, *3.4 Techno-economic analysis - Part 1 energy options*[18]).

The SCADA data and the aggregated smart meter data provided by AusNet Services is the aggregate loads at the meter point from the medium voltage network. This metered load for the low voltage network is net of existing rooftop solar PV, as the PV generation effectively just reduces the amount of import.

The load profile within boundary 3 was derived by adding back the estimated solar PV self-consumption to the relevant SCADA data. AusNet Services had provided the overall capacity of solar panels on feeder MFA34. Wattwatchers data was used to verify the estimated annual production of the rooftop solar panels and an additional load profile was generated for use in the HOMER model. This is important for distinguishing the underlying load from the measured load. from the measured load.

As discussed in Section 3.2, the lack of adequate data from smart meters, and sufficient Wattwatchers devices paired with contextual information, meant that the load could not be calculated on a bottom-up basis at this stage of the project.

The SCADA measured load was adjusted to take account of the self-consumption of the electricity generated from existing installed rooftop PV panels[aa]. Figure 9 gives a schematic of the load and the PV modules within HOMER. Two rooftop solar PV modules were created, shown as PV-NE and PV-NW, in addition to the module tailored to newly added rooftop PV panels, shown as just PV. PV-NE and PV-NW reflect the estimated power generation and cost of the existing installed rooftop solar PV panels. These were considered adequate for modelling the existing installed panels' orientation – northwest and northeast. It should be highlighted that modelling was manipulated to force the optimisation to incorporate the existing installed PV panels[bb]. To account for the self-consumption of the electricity generated from these, a second electric load module was considered in HOMER. For reasons of transparency, it was decided not to merge the synthesised self-consumption data with the relevant SCADA data[cc].

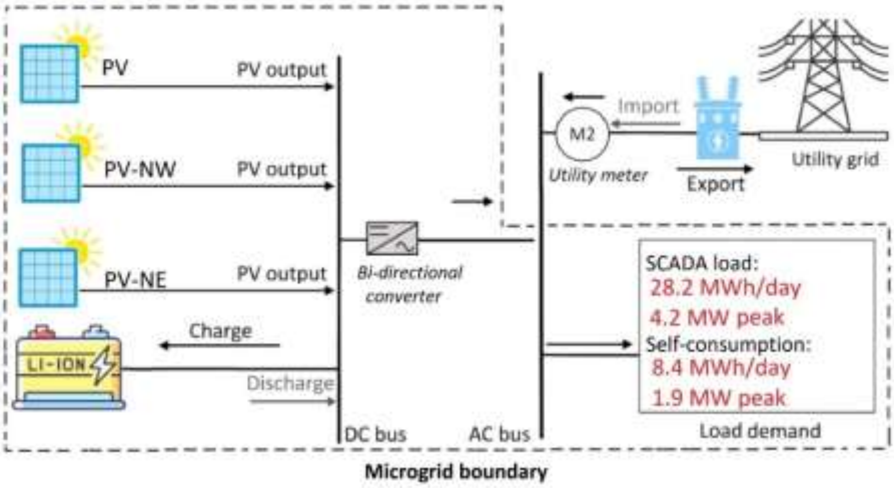

Figure 9 Schematic diagram of the microgrid without bioenergy

[aa] Note that this approximation is valid even under the assumption that households and businesses do not considerably alter their demand patterns to increase the self-consumption of the power generated from their rooftop PV systems. From the network perspective, the impact of privately purchased rooftop solar PV systems on the aggregate small-scale end-users' load profiles can be modelled by simply subtracting the electricity generated by their solar PV systems from the total electricity demand.

[bb] If this was not done, the existing panels would have always been rejected by the optimisation given the lower (remaining) lifetime of the existing panels compared to new ones. To prevent this, a fixed value was entered for the size of PV-NE and PV-NW in the *search space*, the set of all possible system configurations over which HOMER can search for the optimal system configuration. In other words, the size of PV-NE and PV-NW was assumed to be known *a priori*, and therefore, they were not treated as decision variables in the optimisation problem.

[cc] Note that as the existing rooftop PV panels are forced into the optimal solution mix, and as the employed cycle-charging dispatch strategy prioritises self-consumption of locally produced renewable power generation over storage and export, it can be guaranteed that the load demand representing self-consumption is supplied by onsite solar PV generation.

Load characteristics

The total annual electricity consumption within Boundary 3 is estimated to be ~18.7 GWh, of which ~3 GWh is supplied by existing installed rooftop solar PV generations. Therefore the total annual net energy import from the utility grid is ~15.7 GWh. With a total annual energy consumption of ~5.4 GWh, the timber manufacturer load constitutes a sizeable portion of the total load[dd]. This means that, excluding the timber manufacturer load, the boundary of interest is associated with a total annual load of ~13.3 GWh, and a total annual net grid import of ~10.3 GWh[ee]. It is also noteworthy that the overall load demand profile (including the timber manufacturer load and with adjustments for the self-consumption) is associated with a ~5.2 MW peak, while the timber manufacturer load is exclusively associated with a ~2.1 MW peak[ff]. *Appendix D Illustrative profiles* gives an overview of the year-long total electricity consumption profile within boundary 3 including the year-long power demand of the timber manufacturer, with some representative hourly-basis, daily power load and solar PV power generation profiles to better understand the contribution of rooftop solar PV generation in serving the load demand and its dynamics.

6.3 The scenarios

Two primary scenarios have been considered, considered, one with and one without bioenergy. The scenario without bioenergy also excludes the timber manufacturer load.

The optimisation software assumes that any resource within the microgrid is operated in an integrated manner. This would mean, for example, that the timber manufacturer load would use solar at times when that is most economic for the entire system (for example, when it would otherwise be curtailed), and that the bioenergy plant would be operated when there is a lack of output from the solar PV. A microgrid independent of the potential bioenergy generator at the timber manufacturer (and hence its power load) was modelled for a number of reasons:

The community may wish to make decisions independent of the timber manufacturer.

Operating the bioenergy plant in an entirely integrated manner may not make the most business sense for the timber manufacturer, which in general terms will get the best return and lowest risk from maximising their own self-consumption.

The energy consumed by the timber manufacturer is approximately one third of the total town consumption, so if the microgrid were to be independent (and not include bioenergy), it would not supply the timber manufacturer load.

Other communities may not have a potential bioenergy generator, so the results without the bioenergy will be more widely relevant.

Preliminary results indicated that centralised solar PV panels and wind turbines are not economically viable options compared to rooftop solar PV and bioenergy technologies (i.e., they were never selected in the optimisation model) and, therefore, were not investigated further.

Scenario 1 – Heyfield with no bioenergy (and without the timber manufacturer load)

This uses the estimated load for boundary 3, minus the timber manufacturer load. Existing solar generation is included, with a reduced CAPEX corresponding to the estimated remaining lifetime[gg]. The following sensitivities were modelled:

[dd] All energy consumption estimates are based on historical data for the year 2020.

[ee] Note that no privately purchased solar PV system is currently installed at the timber manufacturer.

[ff] Note that the timber manufacturer's peak demand does not coincide with the non-timber-manufacturer peak load – which is adjusted for the rooftop solar PV self-consumption.

[gg] The CAPEX for existing PV is included as a surrogate for calculating the additional operating costs to compensate solar owners for their investments. Using a zero CAPEX for existing PV, in the absence of other compensating measures, would be equivalent to solar owners gifting their installed generation to the town.

a) High and low network lease costs ($0.9 m and $0.6 m).

b) A capacity limit was imposed on imports from the grid in order to force a higher proportion of locally generated electricity. Three different import limits were tested, 1 MW, 1.5 MW, and 2 MW.[hh] There are various ways that higher local generation could be forced into the system; however, setting import limits is also a means by which any network benefits can be realised, as network costs are directly related to the peak load that must be supplied.

All combinations of network costs and the three import limits were tested, giving six scenarios without bioenergy.

Scenario 2 – Heyfield with bioenergy (and the timber manufacturer load)

This uses the estimated load for boundary 3, including the timber manufacturer load. Existing solar generation is included as in Scenario 1. Network costs were set at the higher level ($0.9 m) in order to maintain AusNet Services income close to the original level, noting that network charges on imports were lower in this scenario. The following sensitivities were modelled:

a) A capacity limit was imposed on imports from the grid in order to force a higher proportion of locally generated electricity. Only two different import limits were tested, 1 MW and 1.5 MW

b) High and low levels of bioenergy CAPEX were tested ($2000 and $4000 per kW)

c) High and low bioenergy fuel costs ($19/tonne and $60/tonne).

All combinations of CAPEX and fuel costs were tested with the 1 MW import limit, but only the two extremes (high CAPEX and fuel cost, and low CAPEX and fuel costs) with the 1.5 MW limit, so altogether six scenarios with bioenergy were modelled.

Initially, a higher lease cost of $1.2m was modelled, set at the current estimated AusNet Services income from Heyfield. However, initial results indicated that $1.2m total income AusNet Services was reached with the lower lease costs once the network charges on imports were included.

6.4 Inputs and assumptions

Table 7 lists the key cost inputs and assumptions, in particular where a minimum and maximum value was used to test the sensitivity of the results. Table 8 lists key financial parameters. *Appendix C Inputs and assumptions for economic modelling* gives a full list of inputs and assumptions.

The load profiles and costs have been assumed to remain steady through the project lifetime, and the modelling has not included the potential for load flexibility or energy efficiency.

While a number of the assumptions used are simplifying for practical reasons, the modelling detail is deemed sufficient to derive meaningful insights for this step in the microgrid feasibility process.

Table 7 Key inputs and assumptions – CAPEX and OPEX

Item	Unit	Minimum	Maximum	Comment
Lease cost of the network (from AusNet Services)	$m/ year	$0.6	$0.9	Set to maintain current AusNet Services income of $1.2m[ii]

[hh] Initially this limit was not imposed; however, in that case very little additional generation was installed, as the cheapest solution was importing electricity from the grid.
[ii] Initially a higher lease cost was modelled, set at current AusNet Services income from Heyfield. However, initial results indicated that this level was usually reached with the lower levels once the network charges on imports were included.

Item	Unit	Minimum	Maximum	Comment
Microgrid CAPEX	$m	0.58		From the costs detailed in Table 21[jj].
Microgrid OPEX[kk]	$m/ year	0.043		OPEX was held constant across both scenarios. This figure only includes maintenance and inspection of network assets.
Battery CAPEX	$/kWh	800		Including installation costs
PV CAPEX (rooftop)	$/kW	1,400		Excluding the hybrid inverter costs
PV CAPEX (centralised)	$/kW	1,500		Excluding the hybrid inverter costs
Bioenergy CAPEX	$/kW	2,000	4,000	Assuming that the system is installed at the timber manufacturer
Bioenergy replacement cost	$/kW	4,000	6,000	The bioenergy replacement cost was assumed to be greater than the corresponding CAPEX by $2000/kW due to the necessity to replace additional items (e.g., fuel handling equipment) excluded from the basic CAPEX as they are already in place.
Bioenergy fuel cost	$/tonne	19	60	The biomass feedstock opportunity cost. A value of $44–90/tonne is estimated for high grade sawdust used in bioethanol, briquettes or wood pellets, and a value between $15–106/tonne for residues used in standalone biomass generators[19]

Table 8 Key inputs and assumptions – financial

Parameter	Unit	Value	Comment
Retail charges (within the microgrid)	$m/ year	0.3	This total amount is based on 3c/kWh for the energy consumed within the microgrid in the non-bioenergy case, and is kept constant across both scenarios
Solar feed in tariff	c/KWh	4	This is factored into current solar household's electricity bills, assuming 30% of self-consumption. No FIT is payable to the microgrid.
Export value of generation	c/KWh	Time series	Based on the 2020 wholesale energy market values, assuming that exports between 11am and 3pm are zero value
Cost of imports	c/kWh	Time series	Based on the 2020 wholesale electricity market value for energy + network charges based on the 2020 NSP81 & NSP82 tariff code, with an assumed retail margin of 4 c/kWh

6.5 Initial techno-economic results

6.5.1 Optimisation (physical) results

Table 9 gives initial physical results from the optimisation for all the scenarios, and shows outputs including the percentage of local supply, the battery autonomy hours, the MW of each type of generation and the amount of battery storage. The local supply is given in two ways, the net percentage after imports and

[jj] These costs were revised after the analysis and are somewhat higher ($0.6m), but the change is not sufficient to make a material difference.
[kk] For modelling purposes several other fixed annual costs were included with microgrid OPEX, including the network lease costs, estimated retail charges within the microgrid, and network demand and standing charges.

exports are taken into account, and the amount of consumption which is sourced from local generation at the time it is used[ll]. These results are summarised in Table 9, and more detailed results can be found in *Appendix E Additional results: microgrid economic feasibility*.

Scenario 1, without bioenergy,

The net percentage of local electricity supply[mm] varies from 94% with an import limit of 1 MW, to only 47% when the import limit is set at 2 MW. In this latter case, only 2.5 MW of additional PV is installed. Given that an important community aspiration is to increase the amount of local generation, and it is likely that the current percentage of local electricity supply is close to 40%, this scenario is not considered suitable for the microgrid. It should be noted that if the export limit is lifted further, even less PV is installed and the net percentage of local generation falls even lower.

In the scenarios with 1 and 1.5 MW import limits (94% and 71% net local generation, respectively), there are an additional 7 – 16 MW of PV installed, and 7 – 26 MWh of storage. Of course, with the additional generation, curtailment also increases, and there is 37% curtailment when the import level is only 1 MW. This is because there is a technical limit on exports and installing sufficient PV and batteries to keep imports below 1 MW means there is a great deal of excess generating capacity within the microgrid.

Battery autonomy hours increase as the import limit comes down, going from only one hour in the 2 MW case, to 7 hours in the 1.5 MW case, and to just over a day (26 hours) in the 1 MW case. This is to be expected, as less reliance on imports will inevitably mean the system needs more dispatchable energy – which can be supplied either by storage or by dispatchable power such as bioenergy. The calculation of battery autonomy hours assumes full load, so an emergency supply could be maintained for considerably longer provided appropriate controls were in place.

Scenario 2, with bioenergy,

Local supply percentage is higher in the bioenergy scenarios. The net percentage of local electricity supply varies from 82% in the higher cost bioenergy case where the import limit is 1.5 MW, to 111% in the low bioenergy cost case where the import limit is set at 1 MW. Between 3.7 and 7.1 MW of additional PV is installed, and between 1.6 and 5.5 MWh of storage.

Battery autonomy hours, which indicate resilience, are much lower, at about 1.5 hours in the 1.5 MW import limit case, and between 4.7 and 5.5 hours in the 1 MW import case. However, this may not necessarily mean Scenario 1 is more resilient, as the bioenergy plant can operate independent of the grid. Therefore, to quantify the resilience in terms of the amount of time that the microgrid can sustain the full load during an indefinite grid outage using onsite generation infrastructure, the fraction of the energy delivered to the load that originated from onsite renewable energy sources (solar PV and bioenergy) can be used. This indicator, which is commonly referred to as the renewable fraction[20] is also a reliable measure of self-sufficiency in terms of the expected contribution of local generation to serving the loads in a microgrid context, which is sometimes alternatively referred to as the grid outage survivability[nn].

Accordingly, increasing the import limit decreases the resulting renewable fraction due to the increased opportunity for the system to leverage comparatively low-cost imports. However, the resulting renewable fraction is less sensitive to changes in the value of the import limit in the cases with bioenergy compared to those without bioenergy. This can be attributed to the dispatchability of bioenergy, and consequently, the reduced overall volume of imports, though the peak import (observed from the relevant output time-series data) in all cases is controlled by the associated import capacity constraint – as it allows for a more cost-efficient way to deal with peak net loads.

[ll] This is commonly called the renewable fraction, and also called the self-sufficiency percentage.
[mm] Defined as the MWh of local generation divided by the energy consumed within the microgrid
[nn] The term 'renewable fraction' does not best describe what the indicator measures in all contexts, as most utility grids are not 100% fossil fuelled, and the Australian grid is expected to be close to 70% renewable by 2030. However, assuming a grid-connected microgrid with only renewable generation technologies (i.e., not using diesel gensets), the indicator can adequately quantify the community's level of energy resilience against extended, prolonged grid outages without considering the amount of energy stored in the battery bank. That is, it might be a better strategy to discharge the energy stored in the battery bank to continue to operate critical loads during a more severe outage event that disrupts access to the electricity generated from the onsite renewable sources and the grid – as an additional layer of resiliency.

Table 10 gives some additional physical results for the intermediate bioenergy cost scenarios (high bioenergy CAPEX and low bioenergy fuel costs, and vice versa). The fuel cost has more impact on levels of bioenergy operation, as evidenced by the lower PV and battery installations in the low fuel cost scenario. However, the outcomes are similar in both cases.

Table 9 Scenarios with and without bioenergy – physical results

	Local supply		**Battery autonomy**	**Curtailed local generation**	**New rooftop PV**	**Storage**	**Bioenergy**	
	Net	Time of use	Hours		MW	MWh	MW	**local energy**
Scenarios without bioenergy								
Import limit 1 MW	94%	72%	12.3	37%	16.0	26.3	-	-
Import limit 1.5 MW	71%	57%	3.4	13%	7.0	7.2	-	-
Import limit 2 MW	47%	42%	0.5	0%	2.5	1.0	-	-
Scenarios with bioenergy								
Bioenergy cost high Import limit 1 MW	96%	85%	1.9	4%	6.1	5.5	2.0	37%
Bioenergy cost low Import limit 1 MW	111%	92%	1.6	6%	7.1	4.7	2.0	55%
Bioenergy cost high Import limit 1.5 MW	82%	74%	0.5	3%	5.2	1.5	2.0	33%
Bioenergy cost low Import limit 1.5 MW	94%	84%	0.6	1%	3.7	1.6	2.0	54%

Note – the network lease cost in the case with bioenergy was varied but made no difference to physical results; the network lease cost in the bioenergy scenario was always set at the higher amount.

Table 10 Additional intermediate cost scenarios with bioenergy – physical results

Import limit 1 MW in both cases	Local supply (net) %	Curtailed local generation %	Battery autonomy hours Hours	New rooftop PV MW	Storage MWh	Bioenergy capacity MW	Bioenergy % local energy %
Bioenergy CAPEX low, fuel cost high.	102%	6%	1.6	6.7	4.8	2.0	48%
Bioenergy CAPEX high, fuel cost low	103%	3%	1.5	5.6	4.5	2.0	53%

The scenario with bioenergy has lower costs and higher local energy supply because the bioenergy generation is dispatchable. However, this assumes that the generator is run to optimise conditions for the entire microgrid, which may or may not be the most beneficial economic solution for the timber manufacturer.

Figure 10 shows some typical generation profiles for bioenergy and PV generators in Scenario 2. Specifically, the profiles represent the days where solar PV generation is highest and lowest in the case with an import limit of 1 MW, high bioenergy CAPEX, and high fuel cost. The bioenergy plant operates, on average, 51% of the time across all scenarios[oo]. If the timber manufacturer operated the bioenergy independent of the microgrid, it is likely that it would simply operate when the mill is running. However, these

[oo] The range is 35% in the high CAPEX, high fuel cost scenario with an import limit of 1.5 MW; in all others, the range is between 47% and 58%

hours are selected to complement the PV generation by the optimisation framework. This is consistent with the recent paradigm shift from using bioenergy for serving baseload electrical power to treating it as a system balancing option in a highly renewable grid[21]. That is, bioenergy is increasingly recognised as one of the most cost-effective means to provide flexibility over short-term to long-term and seasonal time frames to effectively manage the variations in power outputs of variable renewables like solar PV[22]. This is commonly referred to as the "value-optimised" use of bioenergy resources[23], indicating that bioenergy could compete with the other options in the system for the provision of flexibility – battery storage and grid exchanges in Heyfield – rather than being a substitute for baseload power production.

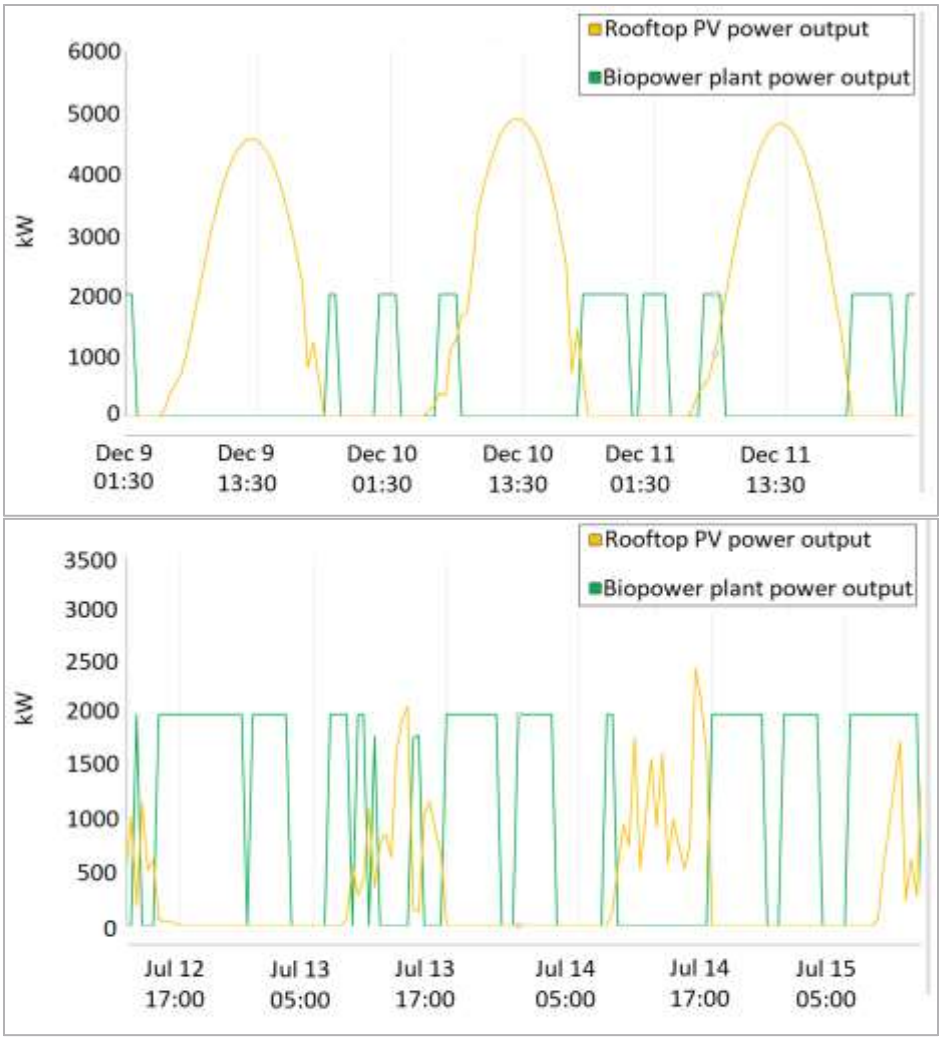

Figure 10 Sample generation profiles for the bioenergy and PV generators in Scenario 2

6.5.2 Estimated economic results overall and by stakeholder

Scenarios without bioenergy

Table 11 gives the initial economic results for each scenario. Looking at the scenarios without bioenergy, initial CAPEX to set up the microgrid varies from $9m – $48m; if the 2 MW scenarios are disregarded as they result in less than 50% local generation, the initial CAPEX required is between $20m – $48m.

Looking at the estimated impact on resident bills, all these scenarios result in bills going up, by between 8% and 100%. We examined the outcome for homes with solar installed and those without. Only residents without solar see any improvement in energy bills, and that is only when the import limit is set so high that the majority of energy is imported. Residents with solar are worse off because they currently get feed in tariffs for solar exported to the grid[pp], which will not be available if they become part of the microgrid. This means their bills go up even in cases where the microgrid energy costs are fairly close to the baseline.

Table 11 Scenarios with and without bioenergy – economic results

	Total CAPEX	LCOE	AusNet annual income	Change in average residential bill ($/year) *(+ means bill goes up)*	
	$m	c/kWh	$m/year	no solar	with solar
Baseline	-	27.4	$1.2	-	-
Scenarios without bioenergy					
Network $$ high, import limit 1 MW	$48.9 m	46.9	$1.1 m	+$891	+$712
Network $$ low, import limit 1 MW	$48.9 m	44.7	$0.8 m	+$789	+$649
Network $$ low, import limit 1.5 MW	$20.2 m	27.6	$0.9 m	+$12	+$171
Network $$ high, import limit 1.5 MW	$20.2 m	29.9	$1.2 m	+$114	+$234
Network $$ high, import limit 2 MW	$8.7 m	25.8	$1.3 m	-$74	+$119
Network $$ low, import limit 2 MW	$8.7 m	23.5	$1.0 m	-$176	+$56
Scenarios with bioenergy					
Bioenergy CAPEX & fuel cost high. Import limit 1 MW.	$25.6 m	24.4	$1.1 m	-$134	+$81
Bioenergy CAPEX low, fuel cost high. Import limit 1 MW.	$22.0 m	23.2	$1.1 m	-$192	+$46
Bioenergy CAPEX high, fuel cost low. Import limit 1 MW.	$24.2 m	22.5	$1.1 m	-$221	+$28
Bioenergy CAPEX & fuel cost low. Import limit 1 MW.	$22.4 m	21.7	$1.0 m	-$261	+$4
Bioenergy CAPEX & fuel cost high. Import limit 1.5 MW.	$21.0 m	22.7	$1.2 m	-$212	+$34
Bioenergy CAPEX & fuel cost low. Import limit 1.5 MW.	$14.9 m	19.8	$1.1 m	-$346	-$49

AusNet Services income is maintained close to the estimated current level in most cases, although the case with low network costs and a low import limit has a significant decline, from $1.2m to $0.8m. The LCOE[qq] in both the 1 MW and the 1.5 MW import limited cases is above the baseline value of 27.4 c/kWh in all modelled cases, which will be reflected in higher energy bills.

Scenarios with bioenergy

Table 11 gives the initial economic results for each scenario. Those with bioenergy are much more promising in terms of economic viability. Initial CAPEX to set up the microgrid varies from $22m – $26m; and the LCOE is lower than the baseline in all cases.

[pp] Bill calculations assume the feed in tariff is valued at 4c/kWh; some residents will currently receive more than this so they would be more badly affected by the change.
[qq] This has been used to calculate estimated residents' bills.

Looking at the estimated impact on resident bills in Figure 11, all of the scenarios with bioenergy result in bills going down for residents who do not have solar installed, by between 10% and 25%. Residents with solar installed are between 11% worse off and 7% better off.

AusNet Services income is maintained close to the estimated current level in most cases, although the case with low network costs and a low import limit sees a significant decline, from $1.2m to $0.8m. The LCOE[rr] in both the 1 MW and the 1.5 MW import limited cases is below the baseline value of 27.4 c/kWh in all modelled cases.

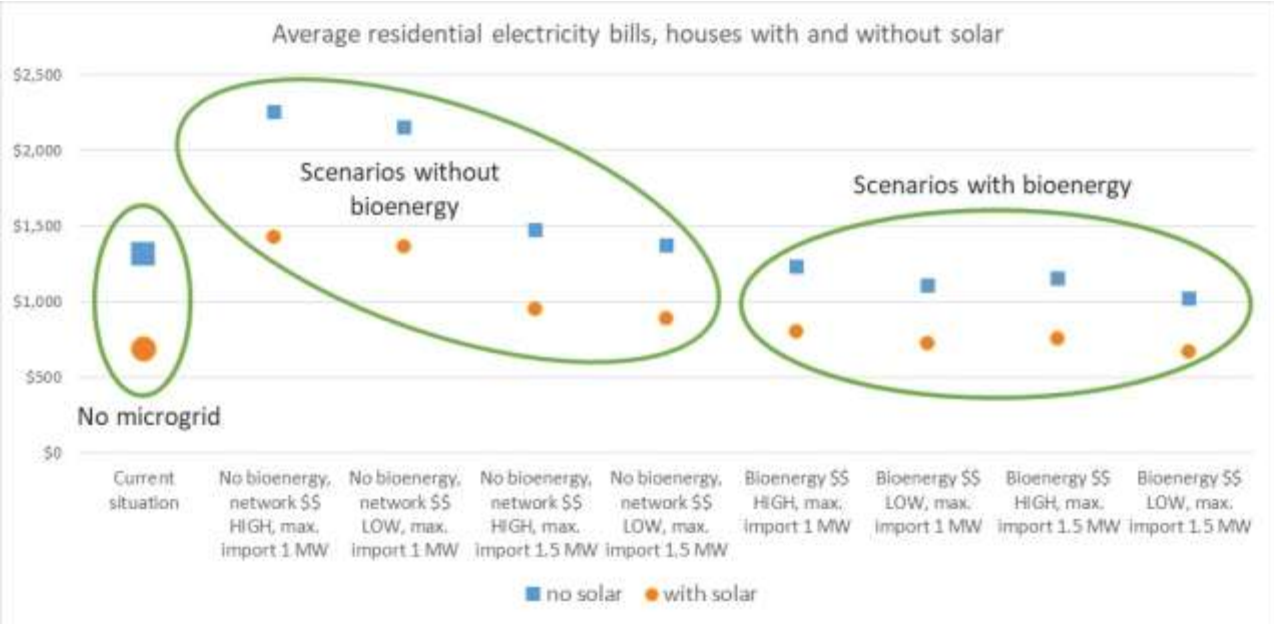

Figure 11 Impact of microgrid scenarios on residential electricity bills

What network benefit would be needed to make it work?

Table 12 shows the network benefit needed from the microgrid, to make the scenarios without bioenergy comparable to the status quo[ss] (of course, if a microgrid was to be implemented, the economics would need to be considerably better than the status quo in order to justify the additional risk). In all the scenarios with a reasonable amount of local generation, between 130 and 1160 $/kVA/year would be needed.

Figure 12 shows indicative network deferral values (equivalent to the network benefit that could be gained from reducing load in an area) for Victoria from the Network Opportunity Maps[24]. There are many caveats on these values, which do not indicate that the network operator is necessarily willing to pay this for each load reduction. However, even as indicative values, the value in the Heyfield area is only $10 – $50/kVA/year, and there is only one location in Victoria where the value reaches $1000/kVA/year.

[rr] This has been used to calculate estimated residents' bills.
[ss] Calculations are based on the total net benefit (in $m/year) being paid for five years; the $/kVA/year is based on the total amount paid divided by the reduction in load, which is calculated by subtracting the relevant import limit from the current peak load of 5.3 MW.

Table 12 Network benefit for microgrid to be comparable with baseline (scenarios without bioenergy)

Scenarios without bioenergy	**Local supply**		**Battery autonomy hours**	**Network benefit needed**	
	Net	**Time of use**		$m/year	($/kVA/year)
Network $$ high, import limit 1 MW	94%	72%	12.3	5.0	1,163
Network $$ low, import limit 1 MW	94%	72%	12.3	4.5	1,047
Network $$ low, import limit 1.5 MW	71%	57%	3.4	0.5	132
Network $$ high, import limit 1.5 MW	71%	57%	3.4	1.0	263
Network $$ high, import limit 2 MW	47%	42%	0.5	-	-
Network $$ low, import limit 2 MW	47%	42%	0.5	-	-

Note: the scenarios with bioenergy do not need a network benefit as they are already comparable.

Figure 12 Network deferral values for Victoria (March 2022)

6.6 Economic modelling – conclusion

Based on the economic modelling results, a number of conclusions can be drawn, namely:

- Scenarios without an import limit set do not result in high proportions of local generation, reflecting the fact that importing energy is in general a cheaper option than converting the town network to a microgrid which may be islanded.
- Scenarios without bioenergy do not appear to be economic, in the absence of providing a significant network benefit, which is not available in the Heyfield area.
- Given that battery storage is cost-prohibitive and grid imports are relatively cheap, it is not cost-optimal to add storage capacity to avoid excess curtailment. Also, where the import limit is low, overbuilding rooftop solar PV panels is a more economical option.

- Scenarios with bioenergy may be economic; however, they require complete integration of the town microgrid with the bioenergy plant. The risks involved would need to be very carefully considered.

- Unlike the scenarios without bioenergy, the excess energy curtailed remains marginal across all scenarios with bioenergy. This is due to the dispatchability of the biopower plant and the fact that it is principally operated to complement solar PV generation.

- The initial CAPEX required is high in all cases; even in scenarios with bioenergy, it ranges from $15 – 25m.

- As the import limit increases, the resulting share of capital-intensive renewable technologies in the energy mix decreases because the system finds the opportunity to use relatively cheap imports.

- A microgrid does offer improved reliability and provides the ability to island in the case of grid outages. If the community placed a high value on increasing the resilience to extremely low-probability high-impact events that might cause serious grid outages in future, this could potentially be a driver of a microgrid for Heyfield, although there may be more economic ways to provide this resilience on a limited scale.

7 Conclusion

This analysis aimed to find out whether a town microgrid in Heyfield is feasible and viable. Some conclusions can be drawn even from this initial study:

- Is a town microgrid technically feasible? – yes.
- Is the microgrid feasible from a regulatory point of view? While there is no clear conclusion, it would certainly involve enormously complex negotiations and may still be turned down by the regulator. None of the standard exemptions apply, and there is no clear route to comply with required consumer protections.
- Is the microgrid economically viable? without bioenergy, no; with bioenergy, yes (with caveats). To know with certainty a microgrid with bioenergy is economic would need more detailed analysis. However, there are very high risks whether economic or not, as the generator would need to be run in an entirely integrated manner. This would mean operating according to the needs of the entire system, including shutting down and using solar PV when there is excess PV generation. This is a high-risk venture for both the business and the community.
- Is the microgrid desirable? This is a decision for the community, however, there are no clear economic advantages, and the risks are very high.

There are conditions that could alter the outlook for any community wishing to investigate a microgrid. The first, and perhaps the most important, is 'network pain' – that is, are there significant network problems that are costing a lot of money. If these are sufficient that the network business might want to implement a microgrid, there would be both financial support and a much easier path to regulatory compliance. However, this is very unlikely to apply in Heyfield. A significant reduction in battery costs and implementing a high degree of load flexibility would also improve the economics.

Overall, further investigation of the Heyfield town microgrid option is not recommended. We recommend instead that the community considers which of the other prospective local energy options or combinations of options are most aligned with community aspirations.

Some of the options potentially worth investigation are shown in Table 13, with an indication on how they compare to previous community aspirations. These options are summarised below.

Table 13 Local energy options compared to some community aspirations

	↓ energy bills	↑ reliability & resilience	↑ community involvement	↑ environmental benefit	↑ Future - - proofing
Town microgrid	✗	✓	✓	✓	?
Energy efficiency upgrade program	✓	✓	✓	✓	?
Load flexibility & control[tt]	✓	✓	✓	✓	✓
Community battery	?	✓	✓	✓	✓
Community renewable generator	✗	✗	✓	✓	✗
Community retailer	?	✗	?	?	✗
Stand-alone power at critical sites	✗	✓	?	✗	✗

[tt] Likely to be implemented with an energy efficiency upgrade, although the technical assessment may be separate.

These are some of the options which may be worth investigation from a technical and economic point of view:

- *An energy efficiency upgrade program* supports the roll out of investments across the community that will make all the buildings, and some industrial loads, suitable for a renewable energy future. Solar panels and batteries will be of interest to many people and out of reach for some, so benefit from being incorporated in the program. Energy efficiency and load flexibility suffer from numerous market and information failures. The program needs to be centred around increased understanding of energy, maximising efficiency, and incorporating the controls for flexibility.
- *Load flexibility & control* is an immature market and would benefit from additional investigations into suitable technologies and technology trials. Hot water has been identified as the major flexible load across Heyfield. Strategies to control hot water and maximise its flexibility need to be thoughtfully designed and defined in the control algorithms. Thermal mass in buildings for heating and cooling flexibility and large refrigeration loads would warrant additional investigations.
- *Community batteries* plus network tariff trials are being supported by the Victorian Government because the energy sector is still learning about the potential advantages and preferred delivery models. It would be timely to develop a “shovel ready” option for Heyfield that could be used to seek government support. This option could include the potential for Islanding at low voltage feeder level with a community battery. Powering the main street, for example, would create a resilient part of the local electricity supply and services from the Railway Hotel, the IGA and the Heyfield Resource Centre could continue during power outages.
- *Stand Alone Power Systems* (SAPS) at critical sites. A number of emergency services could be supported to become critical sites with solar-battery systems. Existing critical sites with generators could be supported to add a battery investment to reduce generator run time and eliminate blackouts – even if the battery only provides 10minutes to 1 hour of emergency power.

If the Heyfield community wishes to implement local energy options, other than as private individuals, a community body will be needed to make decisions, enter into negotiations, promote the solutions, and potentially own or lease assets (this would have been the case for a town microgrid as well). It is recommended that the Community Reference group consider implementing such a body, with the first task to decide which of these immediate energy options is the subject of the remaining effort in this project.

Appendix A Technical feasibility – reliability analysis

Reliability assessment is a part of the planning process in the power system, which considers the different scenarios and the probability of occurrence of various outage events. The assessment considers the random behaviours such as failure of a protection system, feeder, communication, and historical faults to generate scenarios for reliability assessment. Hence it is required to consider the following:

- The failure probability of feeders
- The failure probability of equipment
- The failure probability of new generation and storage.

The overall reliability assessment method is illustrated in Figure 13. From the figure, it is evident that the reliability assessment process required the operational record and historical performance data to assess the reliability through the stochastic process in order to understand the future system behaviour.

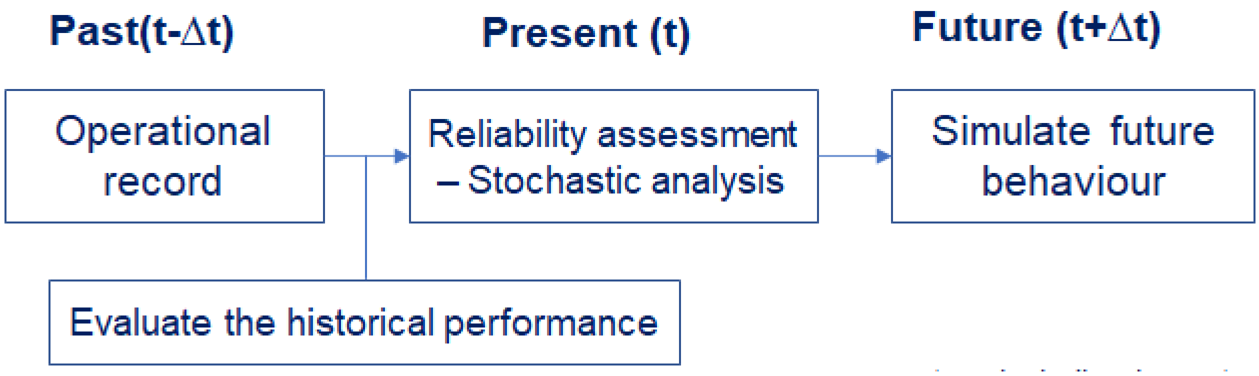

Figure 13 Reliability evaluation process.
Source Adefarati et. al.[25]

The reliability analysis is intended to at represent the service availability to the microgrid community.

The reliability of the system as it stands is influenced mainly by the availability or unavailability of the supply feeder, which is itself influenced by various equipment outages. The microgrid network model has been designed with as many relevant protection devices for reliability analysis as possible, and with an upstream line model (22 kV). The outage probability of the long 22 kV line has been considered here. However, the risk and probability of bushfire and other extreme weather events on the upstream network, zonal substation, and the interruption of the supply and repair are not considered in this study.

Three reliability indices are presented here, namely Energy Not Served (ENS), System Average Interruption Frequency (SAIFI), and System Average Interruption Duration (SAIDI). The reliability calculation was performed considering a one-year planning horizon timeframe. These indices are explained in Table 14.

Several input parameters are required for the reliability studies, such as each network component's outage data and repair time. However, most of the Australian distribution system operators do not record detailed reliability parameters for the LV/MV distribution network. Therefore, the generic parameters obtained from the literature in consultation with utility and similar microgrid projects are used for this study[25,26,27,28]. These parameter values have been summarised in Table 15.

Table 14 Reliability indices

Reliability index	Description	Equation
SAIFI **System Average Interruption Frequency Index**	The total number of interruptions for the average customer during a predefined period of time.	$SAIFI = \frac{\sum Number\ of\ customers\ interrupted}{Total\ number\ of\ Customers\ Served}$
SAIDI **System Average Interruption Duration Index**	The total duration of interruption for the average customer during a predefined period of time, commonly measured in “customer minutes” or “customer hours” of interruption.	$SAIDI = \frac{\sum Customer\ Interruption\ Durations}{Total\ number\ of\ Customers\ Served}$
CAIDI **Customer Average Interruption Duration Index**	The average time required to restore service.	$CAIDI = \frac{\sum Customer\ Interruption\ Durations}{Total\ number\ of\ Customers\ Interrupted} = \frac{SAIDI}{SAIFI}$
CAIFI **Customer Average Interruption Frequency Index**	The average frequency of sustained interruptions for customers experiencing them. The customer is counted once regardless of the number of times interrupted for this calculation.	$CAIFI = \frac{\sum Total\ Number\ of\ Interruptions\ Occured}{Total\ number\ of\ Customers\ Affected}$
ENS **Energy Not Served Index**	This index is measured in MWh/annum and represents the total amount of energy not supplied to system loads due to outages.	

Table 15 Reliability assessment parameters

Component	Reliability Parameters	
	Failure frequency (1/year)	Repair duration (hours/year)
Busbar	0.00225	0.325
Line Segment between two busbars	0.0285 per km	2.04
Transformer	0.02	5.72
Disconnector/Isolator	0.0066	10.8
Fuse	0.0066	10.8
Load	n/a	11

Source *Donald and Tarnagulla Microgrid Feasibility Study* [27]

Table 16 Common mode failure data for PV and battery

Energy Resource	**Failure Frequency** (per year)	**Force Outage Rate** (number **per year)**	**Repair Duration** (hours)
PV Panels	3	0.03	40
Batteries	4.6	0.04	40

The following three scenarios were developed to mimic the microgrid and the non-microgrid situation in the Heyfield area.

- **No microgrid** – the research team modelled the Heyfield distribution system with different penetration of local generation. It is assumed these DERs are considered not available for emergency support in the event of grid outage. This is considered the non-microgrid (current situation) for this study.
- **Microgrid Case 1** – In this scenario, the research team assumed 30% of local generation and storage systems to be capable of emergency supply to support the system in the event of main grid outage. This support could take the form of either PV systems with grid forming inverters, or dispatchable battery systems. In microgrid scenario-1, the research team did not consider an optimal restoration algorithm (i.e., optimal protection coordination to reconnect the system after faults) of the distribution system.
- **Microgrid Case 2** – this scenario is identical to Scenario 1, with the addition that optimal restoration of the distribution system is assumed.

The research team compared the results obtained through the modelling against the reliability indices given for the area in the Regulatory Information Notices (RIN) report[29].

Three local renewable generation levels have been considered for this analysis:

- ✓ 40% DER penetration – 3.7 MW (1,1 MW grid forming capability);
- ✓ 60% DER penetration – 4.0 MW (1.2 MW grid forming capability);
- ✓ 80% DER penetration – 4.8 MW (1.4 MW grid forming capability);

Tables 17-19 present the reliability indices (the ENS, SAIFI, and SAIDI values) with respect to different levels of DER penetrations for no microgrid, microgrid cases 1 and 2, and the area data reported in the RIN (noting that in all cases, a reduction in the indices means an increase in reliability).

The modelled system reliability generally increases as DER penetration levels increase and increases further if there is optimal restoration of the system. It should be emphasised that these are relative values with respect to the stochastic modelling of the system for the given reliability parameters.

A noteworthy difference in the results is observed between the modelled and the reported results. The RIN report records actual outages in the area and the energy not served, SAIFI and SAIDI due to such events. In contrast, the simulation studies generate probabilistic operating scenarios based on the outage date of individual components, lines, and generation and is based on probabilistic analysis; however many elements of the system are not represented in the model.

The modelled results indicate there is likely to be some improvement as DER penetration increases (provided it can provide emergency cover), and in the microgrid cases compared to the non-microgrid case. The actual level of ENS, SAFI, or SADI, cannot be inferred from the modelling, as there is a large difference from the current (non-microgrid) case to the reported results.

Table 17 Energy Not Served results for different scenarios

Penetration of DER	Area data (RIN report) ENS MWh/year	No microgrid **ENS** MWh/year	Microgrid Case 1 ENS MWh/year	Microgrid Case 2 ENS MWh/year
40%	37.02 (1)	69.10	64.98	53.45
60%	-	68.97	56.35	47.85
80%	-	68.96	52.95	40.05

Note 1: ENS values are recorded for the current level of network (%40 penetration level of DER)

Table 18 System Average Interruption Frequency (SAIFI) results for different scenarios

Penetration of DER	Area data (RIN report) SAIFI	No microgrid SAIFI	Microgrid Case 1 SAIFI	Microgrid Case 2 SAIFI
	Interruptions per customer per year			
40%	2.2	6.6	5.5	5.1
60%	-	6.6	4.9	4.3
80%	-	6.6	4.6	3.9

#SAIFI values are recorded for the current level of network (%40 penetration level of DER)

Table 19 System Average Interruption Duration Index (SAIDI) results for different scenarios

Penetration of DER	Area data (RIN report)	No microgrid SAIDI	Microgrid Case 1 SAIDI	Microgrid Case 2 SAIDI
	Minutes per customer per year			
40%	197	287	269	232
60%	-	284	262	208
80%	-	282	255	199

#SAIDI values are recorded for the current level of network (%40 penetration level of DER)

Appendix B Technical feasibility – capital expenditure inputs

The capital expenditure can be obtained as in equation (1).

$$CAPEX = Comp_{cost} + A_{compcost} \quad (1)$$

In (1), $Comp_{cost}$ is the cost of various new microgrid network components required, such as the voltage regulator, the newly added transformer capacity, and the newly added rural feeders, while $A_{compcost}$ denotes the additional cost of microgrid development incurred by, for example, functionality change of the old inverters, reconductoring, the substation load tap changer (LTC) change, reduction of the voltage regulator set point, and so forth.

The cost of the network operation and maintenance can be obtained as:

$$OPEX = \sum C_{main} \quad (2)$$

In (2), C_{main} is the maintenance costs of the equipment such as transformer, LTC, poles and wires. inspection.

Table 20 summarises the upgrading and installation costs which are considered during the techno-economic analyses to estimate the CAPEX and OPEX of the microgrid.

Table 20 Summary of upgrading capital costs

Equipment	Cost
New LTC substation transformer	$310,000 per unit (excludes installation)
New line voltage regulator	$166,000 per unit (excludes installation)
New feeder (rural short)	$142,000/MVA (excludes installation)
Reduce the line voltage regulator set point	$ 2,500
Readjust the LTC set point in transformer	$8,000
Advanced inverter functionality	$143 per inverter
HV Switchgear	$140,000 per unit (excludes installation)
PV	$1400-3340 (note 1) per KW
Bidirectional battery converter	$3000 per kW

Sources: Powercor (2018)[30], Jacobs (2017)[31]

Note 1: 3340 kW is the upper end of the Solar PV cost

A fixed cost for the transformer maintenance was considered ($7,000 per year)[7]. The network inspection costs were calculated on a per-hour rate basis[32] with the costs set to $36,750/year.

Microgrid CAPEX per scenario

Table 21 – Microgrid CAPEX by component, scenario and local generation % (excludes items modelled as part of generation CAPEX)

Local generation %	Unit cost	Scenario 1 Rooftop PV 40%	Scenario 1 Rooftop PV 60%	Scenario 1 Rooftop PV 80%	Scenario 1 Rooftop & central PV 40%	Scenario 1 Rooftop & central PV 60%	Scenario 1 Rooftop & central PV 80%	Scenario 2 Bioenergy, rooftop PV 40%	Scenario 2 Bioenergy, rooftop PV 60%	Scenario 2 Bioenergy, rooftop PV 80%	Scenario 2 Bioenergy, rooftop & central PV 60%	Scenario 2 Bioenergy, rooftop & central PV 80%
Advanced inverter functionality		$72,215	$72,215	$98,813	$72,215	$111,111	$171,314	$72,215	$85,800	$104,104	$72,390	$72,787
Line voltage regulator set point		$7,500	$7,500	$5,000	$7,500	$7,500	$10,000	$7,500	$7,500	$7,500	$5,000	$5,000
New line voltage regulator		$232,400	$232,400	$232,400	$232,400	$232,400	$464,800	$232,400	$232,400	$232,400	-	-
Readjust the transformer set point		$24,000	$24,000	$24,000	$24,000	$24,000	$48,000	$24,000	$24,000	$24,000	$24,000	$24,000
Microgrid controller		$250.000	$250.000	$250.000	$250.000	$250.000	$250.000	$250.000	$250.000	$250.000	$250.000	$250.000
Total		**$586,115**	**$586,115**	**$618,004**	**$586,115**	**$625,011**	**$944,114**	**$586,115**	**$599,700**	**$618,004**	**$351,390**	**$351,787**
UNIT COST AND NUMBER INSTALLED												
Advanced inverter functionality	$143 per inverter	505	505	728	505	508	1,198	505	600	728	506	509
Line voltage regulator set point	$ 2,500	3	3	3	3	3	4	3	3	3	2	2
New line voltage regulator	$166,000 per unit	1	1	1	1	1	2	1	1	1	-	-
Readjust the LTC set point in transformer	$8,000	3	3	3	3	3	6	3	3	3	3	3
Microgrid controller	$250.000	1	1	1	1	1	1	1	1	1	1	1

Note: in the two scenarios with both bioenergy and centralised PV it is assumed there will be a sufficiently large transformer installed to include voltage regulation, so this cost is included in the CAPEX associated with the generation in Table 22.

The source CAPEX for new line voltage regulator listed in Table 22 has been increased by 40% to allow for installation, noting that costs in remote locations may be higher than this.

Table 22 – Microgrid CAPEX by component, scenario and local generation % - additional items included in technical feasibility modelling

These items associated with large new generators were included in the technical feasibility modelling, however the costs are included with the generation technology CAPEX in the economic modelling. The source CAPEX values for all items have been increased by 40% to include installation, noting that costs in remote locations may be higher than 40%.

Local generation %	Unit cost	Scenario 1 Rooftop PV 40%	Scenario 1 Rooftop PV 60%	Scenario 1 Rooftop PV 80%	Scenario 1 Rooftop & central PV 40%	Scenario 1 Rooftop & central PV 60%	Scenario 1 Rooftop & central PV 80%	Scenario 2 Bioenergy, rooftop PV 40%	Scenario 2 Bioenergy, rooftop PV 60%	Scenario 2 Bioenergy, rooftop PV 80%	Scenario 2 Bioenergy, rooftop & central PV 60%	Scenario 2 Bioenergy, rooftop & central PV 80%
New substation transformer		-	-	-	-	$434,000	$868,000	$434,000	$434,000	$232,400	-	$1,736,000
HV Switchgear		-	-	-	-	$196,000	$392,000	-	-	-	$101,346	$588,000
Feeder rural short		-	-	-	-	$437,360	$874,720	-	-	-	$868,000	$1,312,080
Bidirectional battery converter		$4,200,000	$4,200,000	$2,100,000	$2,100,000	$4,200,000	$8,400,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000	$2,100,000
Total	-	**$4,200,000**	**$4,200,000**	**$2,100,000**	**$2,100,000**	**$5,267,360**	**$10,534,720**	**$2,534,000**	**$2,534,000**	**$2,332,400**	**$3,069,346**	**$5,736,080**
UNIT COST AND NUMBER INSTALLED												
New substation transformer	$310,000 per unit	-	-	-	-	1	2	1	1	1	2	4
HV Switchgear	$140,000 per unit	-	-	-	-	1	2	-	-	-	1	3
Feeder rural short	$142,000 per MVA	-	-	-	-	1 (2.2 MVA)	2 (2.2 MVA)	-	-	-	1 (2.2 MVA)	3(2.2 MVA)
Bidirectional battery converter	$3000 per kW	500 kW	500 kW	500 kW	500 kW	1000 kW	2000 kW	500 kW	500 kW	500 kW	500 kW	500 kW

Appendix C Inputs and assumptions for economic modelling

Table 23 Economic modelling inputs and assumptions – CAPEX and OPEX

Item	Unit	Min	Max	Comment
Lease cost of the network (from AusNet Services)	$m/ year	$0.6	$0.9	Set to maintain current AusNet Services income of $1.2m[uu]
Microgrid CAPEX	$m	$0.58		Consists of the costs detailed in Table 21. These costs were revised after the analysis and are somewhat higher ($0.6m), but the change is not sufficient to make a material difference.
Microgrid OPEX (excluding the lease cost)	$m/ year	0.44	0.44	Based on inspection and maintenance of transformers and line, see Table 5.
Bioenergy CAPEX	$/kW	2,000	4,000	Assuming that the system is installed at the timber manufacturer
Bioenergy replacement cost	$/kW	4,000	6,000	The bioenergy replacement cost was assumed to be greater than the corresponding CAPEX by $2000/kW due to the necessity to replace additional items (e.g., fuel handling equipment) excluded from the basic CAPEX as they are already in place.
Bioenergy fuel cost	$/tonne	19	60	The biomass feedstock supply cost (i.e., opportunity cost)
Solar PV CAPEX (rooftop)	$/kW	1,439	n/a	CSIRO, GenCost 2020-1[33]
Solar PV CAPEX (centralised)	$/kW	1,505	n/a	CSIRO, GenCost 2020-1[34]
Solar PV CAPEX (existing)	$/kW	1,439	n/a	The present value of existing rooftop PV was considered with an average remaining lifetime of 20 years
Battery CAPEX	$/kWh	809	n/a	CSIRO, GenCost 2020-1[35]
Battery OPEX	$/kWh/ year	17.8	n/a	The battery OPEX is also aware of the number of hours it is operated over the course of the year[36]
Converter CAPEX	$/kW	400	n/a	Assumes a hybrid AC/DC microgrid with a bidirectional inverter as an interlinking converter[37]
Converter OPEX	$/kW/ year	8	n/a	Calculated based on the mainstream CAPEX-to-OPEX cost ratio for power electronics devices[38]

Table 24 Economic modelling inputs and assumptions – financial and reliability

Parameter	Unit	Value	Comment
Retail charges (within the microgrid)	$m/ year	0.3	This total amount is based on 3c/kWh for the energy consumed within the microgrid in the non-bioenergy case, and is kept constant across both scenarios
Solar feed in tariff	c/KWh	4	This is factored into current solar household's electricity bills, assuming 30% of self-consumption. No FIT is payable to the microgrid.
Export value of generation	c/KWh	Time series	Based on the 2020 wholesale energy market values, assuming that exports between 11am and 3pm are zero value
Cost of imports	c/kWh	Time series	Based on the 2020 wholesale electricity market value for energy + network charges based on the 2020 NSP81 & NSP82 tariff code, with an assumed retail margin of 4 c/kWh
Discount rate	%	5.99	CSIRO, GenCost 2020-1[39]
Inflation rate	%	2	Statista, Australia: Inflation rate from 1986 to 2026[40]
Project lifetime	years	25	The value remaining in the components of the microgrid at the end of the project lifetime (i.e., salvage value) is factored in
Bioenergy plant lifetime	hours	122,640	The expected calendar lifetime (20 years) was converted to an hourly operational lifetime considering a capacity factor of 70%[41]
Lower heating value (LHV) of biomass	MJ/kg	17	LHV as an energy content indicator[42]
PV lifetime	years	25	Assuming a degradation rate of 0.7%/ year[43]
Battery lifetime	years	15	Expected calendar lifetime of the Li-ion battery bank[44]
Export capacity	MW	1.7	Based on the technical feasibility calculations (Refer to Section 5)

Appendix D Illustrative profiles

Figure 15 gives an overview of the year-long total electricity consumption profile within boundary 3 including the year-long power demand of the timber manufacturer with adjustments for self-consumption, while Figure 15 provides some representative hourly-basis, daily power load and solar PV power generation profiles to better understand the contribution of rooftop solar PV generation in serving the load demand and its dynamics.

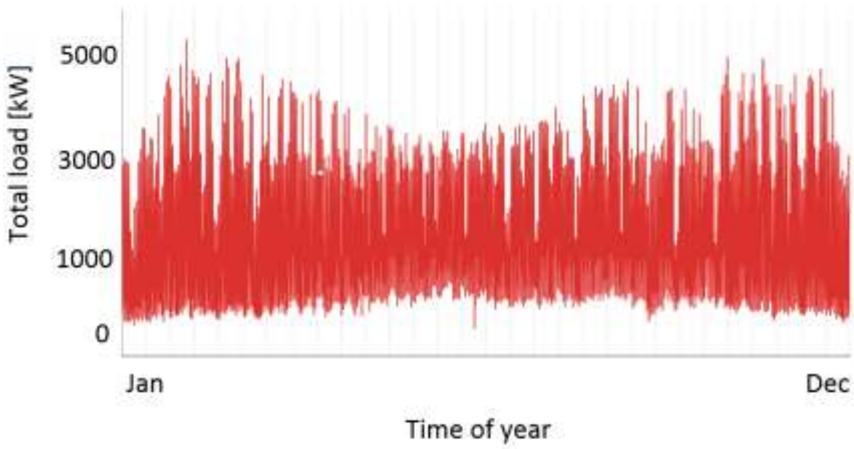

Figure 14 Total load including the timber manufacturer load with adjustments for self-consumption

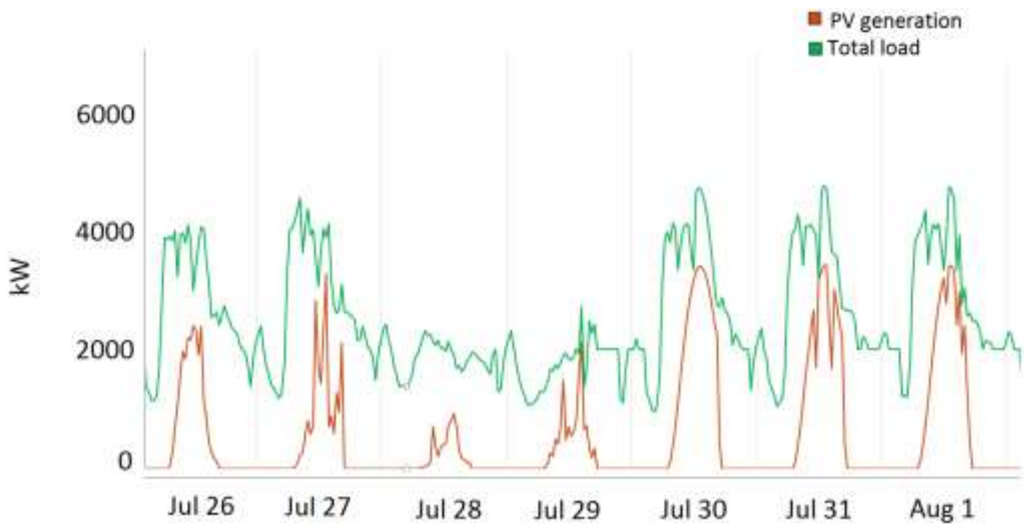

Figure 15 Representative daily profiles for solar PV generation and total load (case with bioenergy and timber manufacturer load)

Appendix E Additional results: microgrid economic feasibility

This appendix gives additional information on the system dynamics and economics of a cost-optimal microgrid solution within boundary 3 with and without the bioenergy plant, and presents more detailed results obtained for the following two cases:

- a rooftop solar PV-battery microgrid case with the 1 MW import limit and $0.9m network lease cost
- a rooftop solar PV-battery-bioenergy microgrid case with a 1 MW import limit, $0.9m network lease cost, $4000/kW bioenergy CAPEX, and $60/tonne biomass feedstock cost.

Case without bioenergy *(1 MW import limit, $0.9m network lease costs)*

Cash flow

In the non-bioenergy-integrated case, the average annualised OPEX is estimated to be $2.79m/year. Figure 16 shows the cumulative cash flow over the project lifetime.

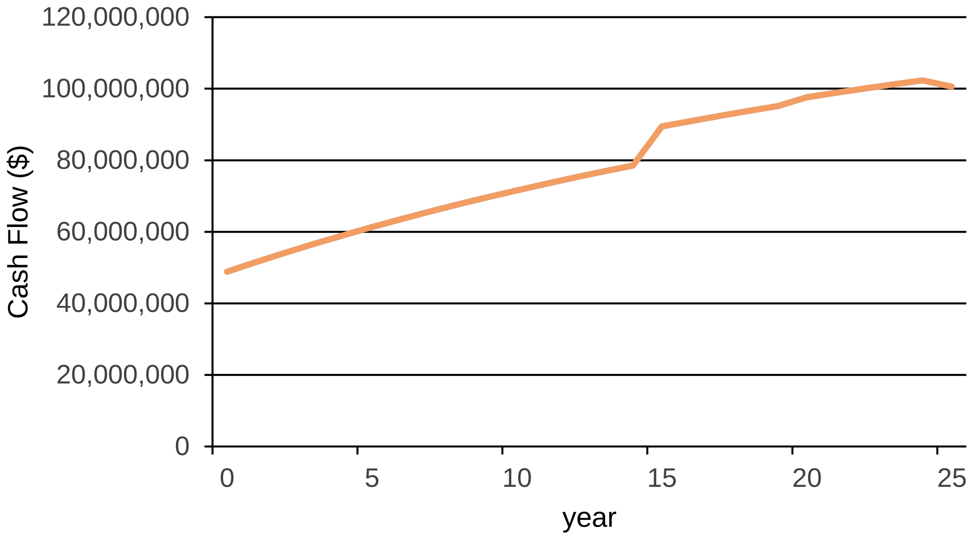

Figure 16 Cumulative cash flow over the project lifetime for the case without bioenergy

Energy flow

Figure 17 provides a breakdown of the contribution of different sources to the total annual energy supplied to the grid-connected PV-battery microgrid on a mean monthly basis.

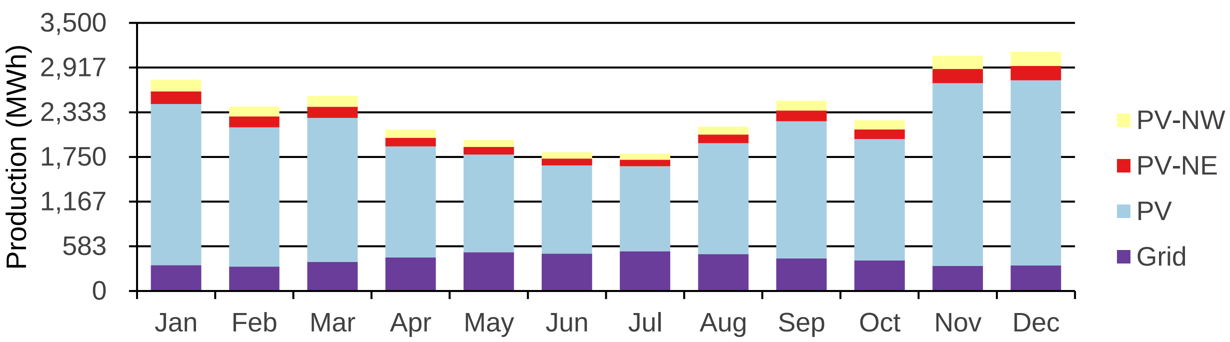

Figure 17 Breakdown of the total energy supplied to the microgrid without bioenergy

Power output from additional rooftop solar PV

In total, the optimal capacity of the new rooftop solar PV is found to be 16 MW with a total annual production of 20.42 GWh/year. The CAPEX and OPEX of new-build rooftop solar PV are $22.3m and $0.41m/year. On average, the additional solar rooftop PV is associated with a specific yield of 1,280 kWh/kW. *Figure 18* displays the hourly power output from the new rooftop solar PV panels.

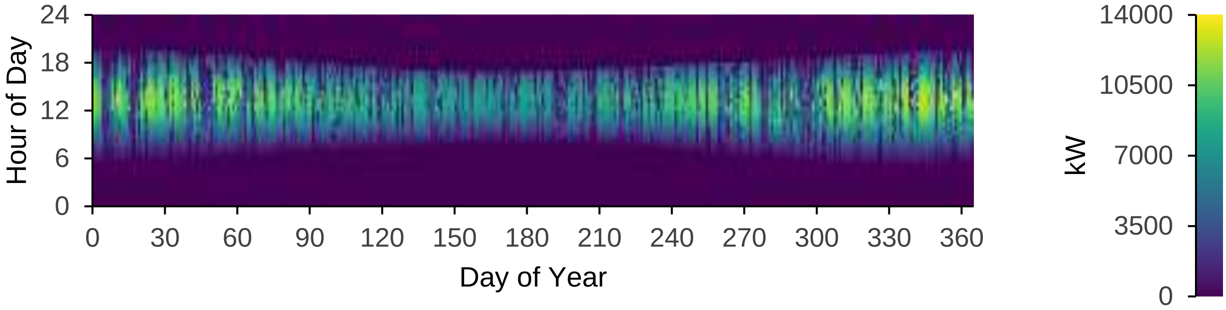

Figure 18 Year-long, hourly-basis power output profile for newly added rooftop PV (without bioenergy)

Dynamics of energy storage

The optimal size of the Li-ion battery bank is found to be 26.3 MWh with an associated annual throughput of 2.12 GWh/year. The CAPEX and OPEX of the battery bank are respectively found to be $21.3m and $0.47m/year.

The battery bank is associated with losses of 183 MWh/year. *Figure 19* depicts the percentage of energy in-store (state-of-charge) for the optimised battery bank at each hour of the baseline year. The battery bank is arguably under-utilised during the summer months, especially when solar is generating. This indicates the potential for leveraging frequency control ancillary services (FCAS) revenues at those times of the year, which might help improve the business case for such a microgrid to some extent.

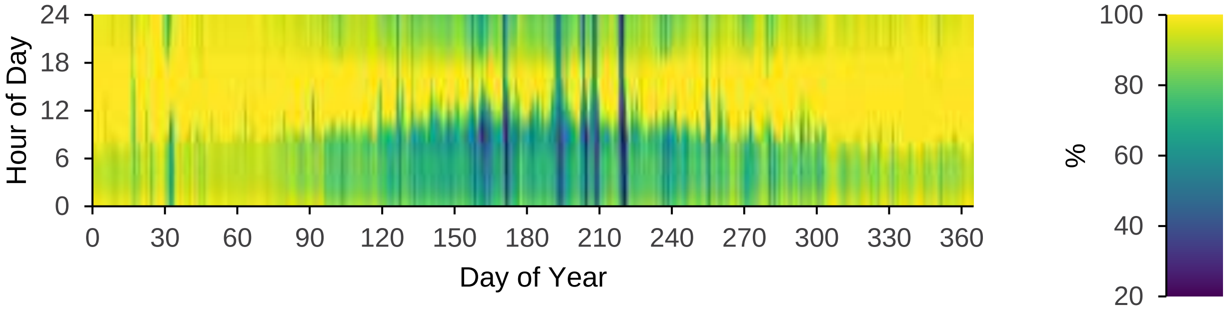

Figure 19 Year-long, hourly-basis profile for the battery state-of-charge (without bioenergy)

Utility grid energy exchanges

Table 25 presents a summary of energy exchanges with the grid over the course of the year.

Table 25 Summary of energy exchanges with the grid (without bioenergy)

Month	Energy Purchased (kWh)	Energy Sold (kWh)	Net Energy Purchased (kWh)	Peak Load (MW)	Total
January	337,537	445,492	-107,955	1	$36,755
February	318,675	377,716	-59,041	1	$36,017
March	378,626	398,222	-19,596	1	$36,237
April	438,021	321,662	116,359	1	$37,351
May	505,792	259,821	245,971	1	$40,207
June	486,766	214,903	271,863	1	$46,486

Month	Energy Purchased (kWh)	Energy Sold (kWh)	Net Energy Purchased (kWh)	Peak Load (MW)	Total
July	518,178	196,393	321,785	1	$52,775
August	482,109	276,749	205,360	1	$54,577
September	424,928	354,834	70,094	1	$60,801
October	397,522	346,825	50,697	1	$65,346
November	326,348	478,939	-152,592	1	$56,471
December	332,586	483,558	-150,972	1	$67,248
Annual	4,947,088	4,155,115	791,973	1	$590,271

Case with bioenergy *(1 MW import limit, high bioenergy CAPEX and fuel costs)*

Cash flow

In the selected bioenergy-integrated case, the average annualised OPEX (including biomass feedstock costs) is estimated to be $2.98m/year. *Figure 20* shows the cumulative cash flow over the project lifetime for the selected case.

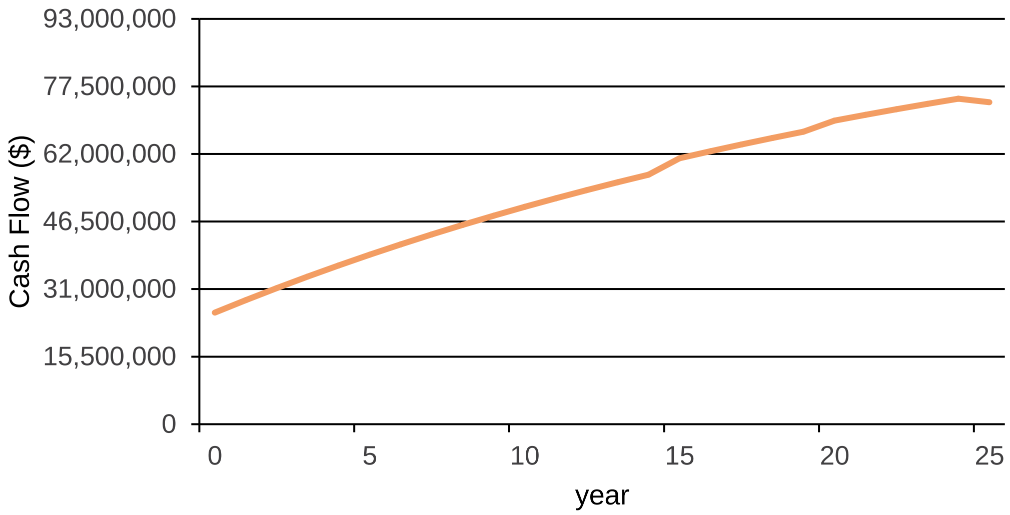

Figure 20 Cumulative cash flow over the project lifetime for the case with bioenergy

Energy flow

Figure 21 provides a breakdown of the contribution of different sources to the total annual energy supplied to the grid-connected PV-bioenergy-battery microgrid on a mean monthly basis.

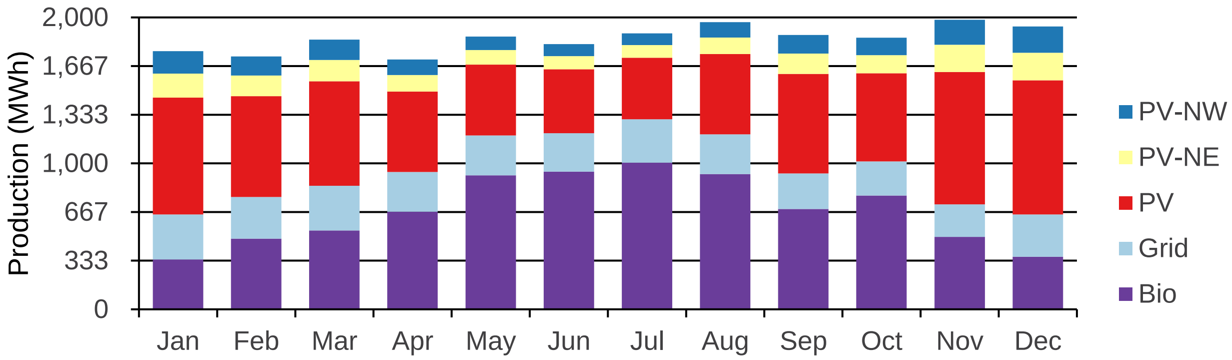

Figure 21 Breakdown of the total energy supplied to the microgrid with bioenergy

Power output from additional rooftop solar PV

In total, the optimal capacity of the new rooftop solar PV is found to be 6.1 MW with a total annual production of 7.77 GWh/year. Also, the CAPEX and OPEX of new-build rooftop solar PV are $8.5m and $0.16m/year. On average, the additional solar rooftop PV is associated with a specific yield of 1,280 kWh/kW. *Figure 22* displays the hourly power output from the new rooftop solar PV panels.

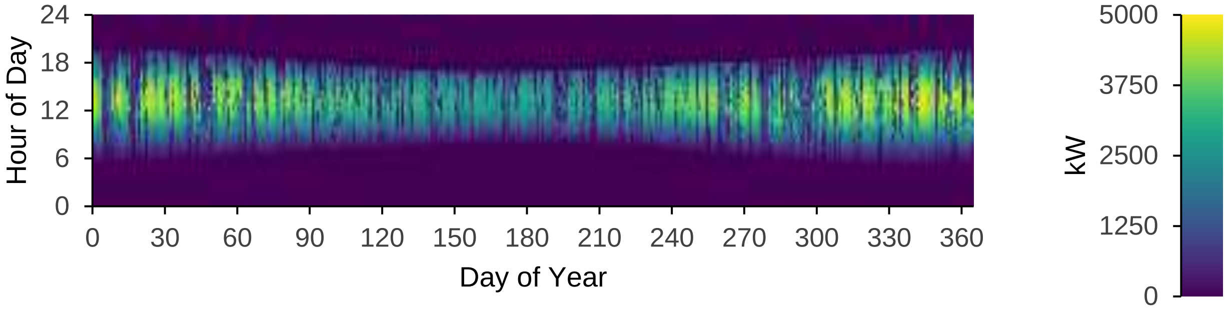

Figure 22 Year-long, hourly-basis power output profile for newly added rooftop PV (with bioenergy)

Bioenergy plant

Power output from the bioenergy plant, rated at 2 MW, is found to be 8.15 GWh/year. The biopower plant's CAPEX and OPEX are $8m and $0.46m/year. Also, the plant is associated with a biomass feedstock consumption of ~6,500 tonnes/year and is expected to operate ~4,100 hours per year. *Figure 23* shows the year-long, hourly-basis profile for the power output from the bioenergy plant.

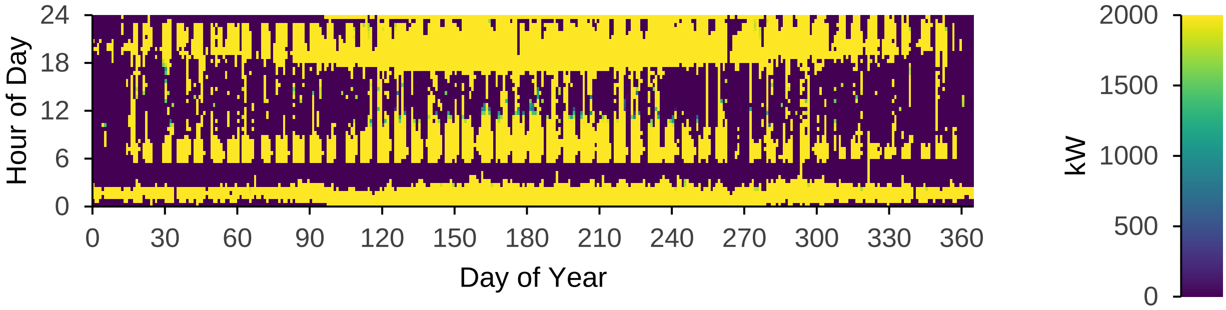

Figure 23 Year-long, hourly-basis power output profile for the bioenergy plant

Dynamics of energy storage

The optimal size of the Li-ion battery bank is found to be 5.5 MWh with an associated annual throughput of 0.77 GWh/year. The CAPEX and OPEX of the battery bank are respectively found to be $4.5m and $0.1m/year. Also, the battery bank is found to be associated with losses of 70 MWh/year. *Figure 24* depicts the state-of-charge of the optimised battery bank at each hour of the baseline year.

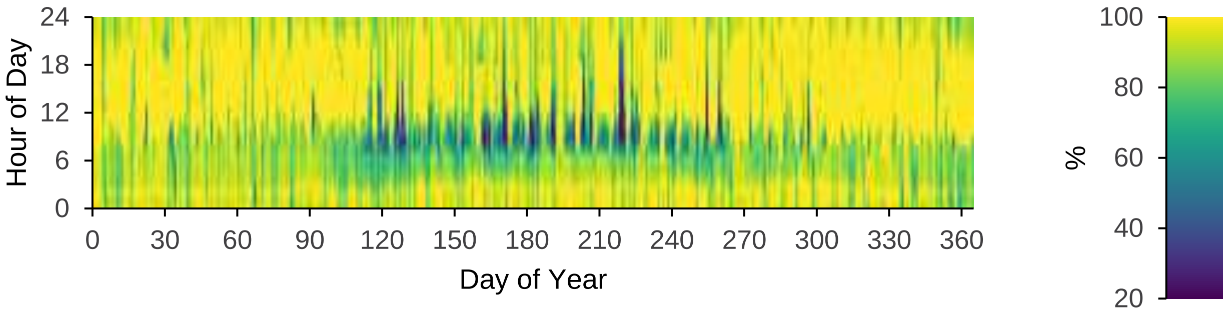

Figure 24 Year-long, hourly-basis profile for the battery state-of-charge (with bioenergy)

Utility grid energy exchanges

Table 26 gives a summary of energy exchanges with the grid over the course of the year.

Table 26 Summary of energy exchanges with the grid (with bioenergy)

Month	Energy Purchased (kWh)	Energy Sold (kWh)	Net Energy Purchased (kWh)	Peak Load (MW)	Total
January	308,636	332,919	-24,283	1	$38,134
February	285,052	217,111	67,941	1	$31,008
March	306,473	231,986	74,487	1	$36,181
April	272,812	160,679	112,133	1	$36,484
May	273,152	99,665	173,487	1	$38,311
June	263,091	95,154	167,937	1	$32,938
July	296,744	70,502	226,242	1	$31,758
August	273,102	146,918	126,184	1	$29,357
September	243,637	238,413	5,224	1	$31,472
October	234,783	175,182	59,601	1	$34,015
November	222,921	343,300	-120,379	1	$27,675
December	289,788	341,115	-51,327	1	$37,226
Annual	3,270,192	2,452,944	817,248	1	$404,559

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