Title: **Project 8: Economic and Risk Assessment – Part I**

Document ID: Final_Report_4908

Date: 24th January 2023

Prepared For: Centre for New Energy Technologies (C4NET)
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Executive Summary

The Donald and Tarnagulla Microgrid Feasibility Study has been launched under a Grant Agreement between the Centre for New Energy Technologies Limited (C4NET) and the Commonwealth of Australia, represented by the Department of Industry, Science, Energy and Resources (DISER). The study includes 12 interdisciplinary projects where Project 8, "Economic and Risk Assessment", was performed by a collaboration between the University of Melbourne and Federation University. This report ("Project 8: Economic and Risk Assessment – Part I") presents the work performed by the University of Melbourne, while detailing when required the contributions from the work performed by Federation University, focused on network reliability and the impact of bushfires in each town. Further detail on the work performed by Federation University can be found in the report "Project 8: Economic and Risk Assessment – Part II". During Project 8 the University of Melbourne developed a microgrid techno-economic assessment framework to analyse the diverse impact the microgrid will have in various relevant stakeholders. This includes economic impact, value, and opportunities created for all grid-users, distribution network service provider, aggregators, retailers etc. during the economic assessment span. The proposed techno-economic assessment framework consists of two-interdependent sub-frameworks. Namely, the techno-economic framework and the commercial framework.

The techno-economic framework is comprised of an integrated investment and operation model and an operational model. The former model allows to make investment decisions in terms of DER technologies, size and location so the microgrid net present value (NPV) and benefits accrued during its operation are maximised, whereas the latter allows to perform more specific operational studies on the different value streams microgrids can access. When compared to previous projects, the techno-economic framework has the following relevant attributes:

- The inclusion of the MV network of each town and relevant operational constraints that impact the value the microgrid can provide to each town.
- The inclusion of uncertainty in future system-level and local conditions using scenario analysis.
- The inclusion of different roles and responsibilities within the microgrid (such as customers, distribution network service provider (DNSP), microgrid operators, aggregators) and their respective costs and revenues.
- The inclusion of different system-level and local value streams using sufficient time granularity that allows to capture extreme conditions where microgrids can provide significant value
- The inclusion of the impact of extreme weather events as well as the microgrid operation in normal conditions for the microgrid investment decisions.
- It considers network investment cost recovery by including the network use of services (NUoS) charges that customers are subject to. Therefore, the underlying assumption is that the DNSP owns the network assets in the microgrid and is in charge of the operation and maintenance of those assets.
- Treating the microgrid as a single entity, in which all the resources in the microgrid are coordinated to achieve the best possible outcome for the community in the aggregate. This allows to generate the most total value from the microgrid project in each town when compared to each DER operated independently. Nevertheless, the best outcome in the aggregate might come at the expense of the private benefit of some individual customers. How the value generated by the microgrid is then allocated equitably to the members of community is a subject for further research.

The techno-economic framework was used to study the optimal investment decisions to form the microgrids in Donald and Tarnagulla, as well as the optimal microgrid operation. This allowed to quantify the value of the microgrid project in each town for specific case studies, assuming certain realisations of uncertain conditions (e.g., wholesale market prices, local demand, DER technology adoption, accessible value streams). The main conclusions from this analysis are:

- Whereas the economic feasibility of a microgrid is uncertain, there are some key value drivers that can significantly impact the feasibility of the microgrid. Importantly, volatile wholesale market prices can result in significant benefits for the microgrid to provide arbitrage, being a key factor in the economic feasibility. Higher penetration of privately-owned customer DER in the community results in significant synergies when also installing microgrid DER, and when all privately-owned DER are operated in coordination with the microgrid DER significant value can be attained. Increasing demand in the community also results in further value created by the microgrid, as these resources can be further utilized to supply the increasing local demand, in particular during peak demand times. Similarly, when comparing Donald and Tarnagulla, Donald is a considerably larger community in terms of network assets and demand. The results demonstrated that a larger community has more potential as an economically feasible microgrid, the microgrid DER being able to leverage the further diversity of demand and generation to provide more benefits to the community, in terms of energy, provision of services upstream and downstream, and resilience.

- The impact of bushfires was included using the expected energy not served (EENS) calculated with probabilistic bushfire and resilience models from Project 7 and Project 8. It must be noted that these results entail certain assumptions regarding failure rates of network assets and DER, bushfire duration, efficiency of PV during bushfires, among others, which are inputs of a probabilistic model. Importantly, *expected* energy not served, is a measure of the impact of bushfires in the town that inherently incorporates the impact of uncertainty and probabilities. In this sense, it is different than the actual energy not served during a bushfire event. However, its value lies on providing an estimation of resilience to bushfires achieved in each town with a microgrid, which can then be introduced as a value stream to quantify the benefits of resilience in the net present value (NPV) of the microgrid.
- When not considering the impact of bushfires, required investment on PV systems is limited for both towns. However, as more severe bushfires occur with more frequency, investment on PV systems and battery systems are recommended to support the microgrid operation during the bushfire events. This analysis is based on the parametric studies that relate EENS and DER size, performed during Project 7. However, it must be noted that certain assumptions in Project 7 might not hold, and thus the role of PV during bushfires might be overestimated. These assumptions are related to the efficiency of PV generation during bushfires as well as the ability of the local network in each community to support a significant increase of PV generation.
- Wholesale market prices are the main uncertain parameter that drives the required microgrid investment, as savings arising from wholesale market arbitrage is the main source of revenues for the microgrid during normal operation.
- Diesel generators are generally recommended as cost-efficient investment decisions that can be dispatched at times of price spikes in the wholesale market, providing significant benefits to the community. However, when diesel generators were not considered as an investment option, investment in batteries significantly increased. While not considering diesel generators results in higher costs for the microgrid project it can come with additional benefits beyond environmental aspects, such as eliminating a source of uncertainty which are fuel costs (or other associated costs with fuel such as taxes aiming to reduce carbon emissions). In the project fuel costs were assumed constant and equal to $300/MWh through the 12 year economic assessment. Additionally, it must be noted that currently diesel generators require relatively lower capital expenditure. However, batteries capital costs have been consistently decreasing in the last years, which might affect the optimal investment decisions detailed in this report, possibly increasing the investment in batteries.
- In most scenarios battery systems were recommended, as these are flexible resources that can provide an array of benefits to the microgrid. In both towns batteries selected range from 1 hour to 2 hour duration.
- When designing a microgrid using expected energy not served (EENS) to quantify the impact of bushfires, the probability associated with bushfires occurrence is a critical parameter. When design considers higher probabilities of bushfire occurrence, investment decisions significantly change from the design without considering the impact of bushfires. Additionally, the impact of assumptions such as PV efficiency during the bushfire, fuel disruption or presence of customer-owned DER will have a relevant impact on the optimal investment decisions.
- When designing a microgrid in a region where severe bushfires are likely to take place, directly including in the investment model credible bushfire events is a critical step to understand the required optimal investment during the event. Severe bushfires, like the two-week bushfire with one week fuel disruption included in the analysis, can yield to actual energy not served that entails unacceptable costs. This was highlighted in the regret analysis, where the investment decisions that considered the costs associated with EENS in the actual bushfire event resulted in high costs of energy not served, and thus high regrets associated with the investment decision.

- Additional value streams can incentivize the microgrid DER to provide valuable services such as peak demand reduction, demand response, network tariff arbitrage or voltage management services. However, these value streams only comprise around 10% of the annual microgrid net cash flows (NCF) and are not the main factor for the microgrid profitability. Nevertheless, as compared to system-level markets such as frequency control ancillary services (FCAS) or wholesale market that have highly uncertain future evolutions, these additional value streams provide a consistent source of revenues for the microgrid during its lifetime.
- Relevant outcomes arise from the collaboration between the University of Melbourne and Federation University. The different investment decisions from the techno-economic framework that are detailed in this report, were introduced in the bushfire dynamic model developed by Federation University. The EENS results developed by Federation University were then introduced in the techno-economic framework, in particular in the NPV analysis, which allowed to quantify in each town an additional value stream: the role of the microgrid reducing EENS during extreme weather events.
- The NPV analysis considering both investment and operational cash flows displays that the microgrid project in Donald and Tarnagulla can provide value to the community and different stakeholders involved, especially when considering the economic impact of bushfires. The NPV analysis points out that the microgrid project in Donald can provide further value. Additionally, when considering the impact of bushfires Donald provides considerably more value than Tarnagulla due to the synergies between optimal investment decisions for "normal operation" and to reduce bushfire impact. To achieve these results, the continuous collaboration between the University of Melbourne and Federation University was critical. Further detail on the work performed by Federation University can be found in "Project 8: Economic and Risk Assessment – Part II".

Starting from the revenues and associated costs quantified through the techno-economic analysis, the value flow mapping model, as part of the commercial modelling framework, was deployed to assess to what extent each actor/stakeholder throughout the value chain might benefit from microgrid operation under different ownerships models and allocation strategies. In this respect, deciding on the roles and responsibilities of each actor (e.g., who finances and owns the microgrid DER assets) greatly impacts on how a microgrid functions, including the accessible value streams as well as the commercial feasibility of the microgrid project itself. Additionally, this is also affected by the relevant regulatory framework that allows any interactions among actors. Therefore, illustrative examples of different commercial models, including prosumers consortium, third-party ownership (i.e., retailer or aggregator-owned microgrid DER assets) and DNSP ownership, were presented with the aim to understand the impact on and the sensitivity of each actor's economic benefit to different value streams allocation strategies. To account for financial strength as well as the different "riskiness" each actor may be subject to under alternative commercial models, the economic assessment, based on the "time-value of money" concept, is performed by applying different discount rates for each actor, and, for the same actor, a different discount rate was applied depending on the "riskiness" of the specific role(s) played. From the analysis, it emerged how a DNSP-owned microgrid DER assets results in a commercial model where both the community members and the third-party benefit from setting up the microgrid. While in these illustrative examples having the DNSP as an investor leads to a slightly positive net present value for the DNSP actor, there are potentially additional benefits that it might be able to accrue (e.g., avoided capital investment on network infrastructure upgrades), also supported by its considerably lower cost of capital compared to other actors under consideration, and particularly the community members. Hence, there is great potential from combining the financial strength of the distribution network service provider with the experience, access to markets information of a competitive market participant, e.g., retailer and/or aggregator, with the ultimate goal of benefiting the community.

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Abbreviations and Acronyms

AEMO	Australian Energy Market Operator
AEO	Australian Energy Outlook
CAPEX	Capital Expenditure
CBA	Cost-Benefit Analysis
EV	Electric Vehicles
DCF	Discounted cash flows
DER	Distributed Energy Resources
DR	Demand Response
DNSP	Distribution Network Service Provider
FCAS	Frequency Control Ancillary Services
LV	Low Voltage
MV	Medium Voltage
NCF	Net cash flows
NPV	Net present value
OPEX	Operating Expenses
OPF	Optimal Power Flow
RERT	Reliability and Emergency Reserve Trader
STPIS	Service Target Performance Incentive Scheme

1 Background

This project is part of a larger project "Donald and Tarnagulla Microgrid Feasibility Study" to assess partial or full microgrid feasibility in two regional Victorian towns with supply vulnerabilities. The two load centres of Donald and Tarnagulla are supplied through long rural lines with high-reliability risks for these communities. The network operators and the community groups in these two towns have been interested in improving the reliability of their power supply by enabling cost-effective fully or partially self-sustaining microgrids. The Donald and Tarnagulla Microgrid Feasibility Study has been launched under a Grant Agreement between the Centre for New Energy Technologies Limited (C4NET) and the Commonwealth of Australia, represented by the Department of Industry, Science, Energy and Resources (DISER). The study includes 12 interdisciplinary projects that commenced in September 2021. In July 2022, Project 8 "Economic and Risk Assessment" was launched.

Project 8 was performed by a collaboration between the University of Melbourne and Federation University. This report ("Project 8: Economic and Risk Assessment – Part I") presents the work performed by the University of Melbourne, while detailing when required the contributions from the work performed by Federation University, focused on network reliability and the impact of bushfires in each town. Further detail on the work performed by Federation University can be found in the report "Project 8: Economic and Risk Assessment – Part II".

Previous projects have addressed issues such as hosting capacity, islanding design, cost analysis and microgrid impact, among others. Project 8 takes as main inputs from previous projects the MV network data from the network model developed in Project 5 using DIgSILENT, smart meter data aggregated to MV/LV transformer level and network reliability studies during extreme weather events from Project 7. Importantly, Project 5 "Islanding Design and Cost Analysis" used HOMER (Hybrid Optimization of Multiple Energy Resources) software to determine the optimal DER to be installed in each town.

Project 8 builds on this work and analyses the optimal microgrid investment and operation with further detail. First, the MV network of each town is considered. This allows to include in the investment decisions the impact of the MV network within each town (e.g., network constraints, locations with higher and lower demand and PV generation), and in turn provides improved estimates on the microgrid costs and benefits as well as allowing to inform on preferred DER locations in each town. Second, the impact of uncertainty in future system-level and local conditions is considered, which enables an improved understanding on the conditions in which the microgrid can provide further value. Third, the microgrid investment and operation models developed in Project 8 allow the inclusion of the different roles and responsibilities within the microgrid (such as customers, distribution network service provider (DNSP), microgrid operators, aggregators) and their respective costs and revenues. This allows to consider further system-level and local value streams that are included with high time granularity capturing extreme conditions where microgrids can provide significant value. Importantly, the impact of extreme weather events as well as the microgrid operation in normal conditions is considered in Project 8 to select investments. In summary, Project 8 enables a more comprehensive understating of the aggregate value the microgrid project provides. This, in turn allows to analyse potential business models which define how value is delivered to the different relevant stakeholders. In particular, it is crucial to identify the most suitable strategy to allocate costs and benefits and ownerships models so as to set-up a win-win situation where microgrids become economically attractive for every actor involved in the project. A commercial modelling framework is developed, to describe all the interactions and values exchanges/relevant economic transactions under different commercial models, and to measure their attractiveness from each actor's perspective. The commercial modelling framework is then applied in some illustrative examples of different commercial models, including prosumers consortium, third-party ownership (i.e., retailer or aggregator-owned microgrid DER assets) and DNSP ownership, to compare and inform the project on the potential effects of different value streams allocation strategies on each actor's benefit.

Overall, this report:

- Provides an overview of the techno-economic assessment framework used in Project 8;
- Describes the main features of the microgrid operational and integrated investment and operation models used within the techno-economic assessment framework;

- Describes the inputs and assumptions around future scenarios required for the microgrid operational and investment models;
- Describes the relevant outputs from the operational and investment models in Donald and Tarnagulla;
- Studies the optimal microgrid investment in Donald and Tarnagulla under different uncertain future conditions, including the risk of bushfires, providing optimal investment size and location;
- Performs a sensitivity study to demonstrate the impact of relevant assumptions on the inclusion of extreme weather events studies from Project 7 in the investment decisions;
- Provides an estimate of the annual net cash flows (NCF) and net present value (NPV) of the microgrid in two scenarios that represent boundary conditions (lower and upper limit) in terms of the value the microgrid can provide to Donald and Tarnagulla;
- Provides a sensitivity study that relates the NPV of the project in Donald and Tarnagulla with different design assumptions on the duration of extreme weather events (i.e., bushfires);
- Presents specific operational studies on the issue of different network tariffs for customers in microgrids;
- Introduces the commercial modelling framework and its sub-models, namely value flow mapping and economic assessment models - Describes the main roles potentially present in the microgrid ecosystem along with their responsibilities and associated value streams;
- Discusses some potential ownership structures (e.g., full financial contribution, equity share, lease) and ownership model options, highlighting the pros and cons of each alternative;
- Compares the potential effects of different value streams allocation strategies on each actor's benefit via some illustrative examples of different commercial models, including prosumers consortium, third-party ownership (i.e., retailer or aggregator-owned microgrid DER assets) and DNSP ownership.

2 Techno-economic Assessment Framework

In this chapter, an overview of the overall framework proposed for the microgrid economic and risk assessment is provided.

2.1 Techno-economic assessment framework overview

The proposed techno-economic assessment framework consists of two-interdependent sub-frameworks. Namely, the techno-economic framework and the commercial framework. The framework overview, with relevant inputs and outputs and information flows among the sub-frameworks is presented in Figure 1.

- Techno-economic modelling framework: that seeks to find the optimal investment and operation of distributed energy resources (DER) in the microgrid to maximize the total economic benefits for the aggregation of all resources and actors present in the microgrid (e.g., DER, all grid-users, distribution network service provider (DNSP)) during its lifetime. This framework involves two models. First, the microgrid integrated investment and operation model, to support decision-making subject to uncertainty providing the optimal DER size and location of the DER to be installed to form the microgrid (referred in this report as "microgrid DER"). Second, the microgrid operational model which takes the optimal DER size and location to assess with higher time granularity and further accuracy the microgrid operation and cash flows during its lifetime.

- Commercial modelling framework: that seeks to identify, quantify, and allocate the costs and benefits to each and every stakeholder/actor involved in the microgrid. It clearly maps the impact of various microgrid architectures to each actor with the value mapping model while measuring its attractiveness also on the basis of the required investment cost, desired return, etc. with the economic assessment model.

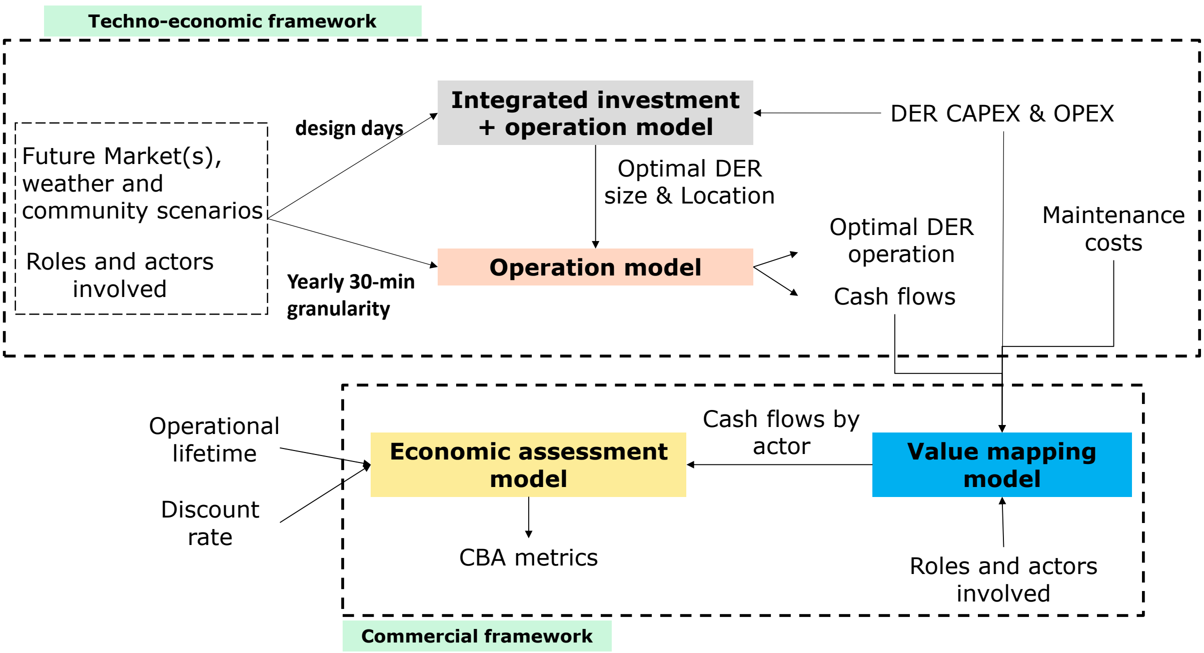


Figure 1. Flow chart of the Techno-economic Assessment Framework, including the techno-economic and commercial sub-frameworks, relevant inputs, outputs and information flows.

2.2 Techno-economic framework introduction

The techno-economic framework is comprised of two models:

- Microgrid integrated investment and operation model
- Microgrid operational model

The microgrid integrated investment and operation model is an optimization program utilized to select the optimal investment on microgrid DER, considering the operation of the microgrid during the whole horizon of the economic assessment. To make optimal investment decisions it is critical to include in the same optimization program the whole horizon of the economic assessment. It is intuitive that in a microgrid project that needs to be assessed for several years this requirement results in a large problem, with the subsequent computational challenges. To avoid these computational challenges the microgrid integrated investment and operation model adopts a linear formulation of the microgrid operation, that can efficiently reflect the main drivers for the need to invest while remaining computationally efficient. Additionally, with the same objective of computation efficiency "design days" are used to represent the microgrid operation each year of the analysis.

Once the investment decisions are made by the microgrid integrated investment and operation model, the microgrid operational model can provide further accuracy in the results. When only assessing the microgrid operation, the problem can be partitioned for specific intervals (e.g., one week, one month) as optimal investment decisions have already been made and with simple considerations the microgrid operation in a specific interval can be solved and then related to the following interval. This allows to study the microgrid operation with more complex and accurate models and for more time-periods to provide better estimates in the resulting cash flows of the microgrid.

In the next sections the two main models in the techno-economic framework (i.e., microgrid integrated investment and operation model and microgrid operational model) are presented in further detail.

2.3 Microgrid integrated investment and operation model: Model overview

The microgrid integrated investment and operation model is based on a centralized multi-period optimization modelled as a linear program. The purpose of this model is to obtain the optimal size and location of the DER to be installed in the microgrid, at MV level. The microgrid integrated investment and operation model selects the optimal DER investment while accounting for the orchestrated operation of the microgrid DER with the remaining flexible resources within the microgrid to maximize the total revenues accrued by the microgrid during its lifetime while considering all technical limits. As the inclusion of investment decisions considering the whole horizon of the economic assessment requires high computational times, a linear program is formulated to guarantee that the problem remains computationally efficient. With a linear formulation, the microgrid integrated investment and operation model effectively captures the main aspects of network operation (power flows and voltage deviation) and DER operation to display the main operational constraints that will affect the optimal DER size and location. Further operational accuracy can be achieved ex-post by the microgrid operational model. The microgrid integrated investment and operation model is implemented following a general and flexible modular approach. The optimisation problem is comprised of:

- An objective function, that drives the microgrid DER investment decisions, and orchestration and operation of all resources of the microgrid;
- Techno-economic constraints that ensure the objective function is optimized while guaranteeing technical and, potentially, contractual limits. The techno-economic constraints are included using a modular approach that ensures the model remains general and flexible. This allows to perform studies on specific actors or resources within the microgrid, as well as performing general studies where the different roles within a microgrid are captured.

This techno-economic operational model builds on the work presented in [1], [2]. The centralized nature of the problem has the underlying assumption that all the involved actors in the microgrid have a common objective (e.g., maximize revenues). Thus, their actions are coordinated to achieve this objective in the aggregate, which is aligned with the general concept of communities within microgrids.

With the microgrid objective formulated, and all techno-economic constraints built, the microgrid integrated investment and operation model finds the optimal solution of:

- Investment on the microgrid DER in terms of size and location in the MV network;
- Microgrid investment costs;
- Microgrid orchestrated operation (microgrid DER, customer resources), and
- Resulting costs and benefits from the operation.

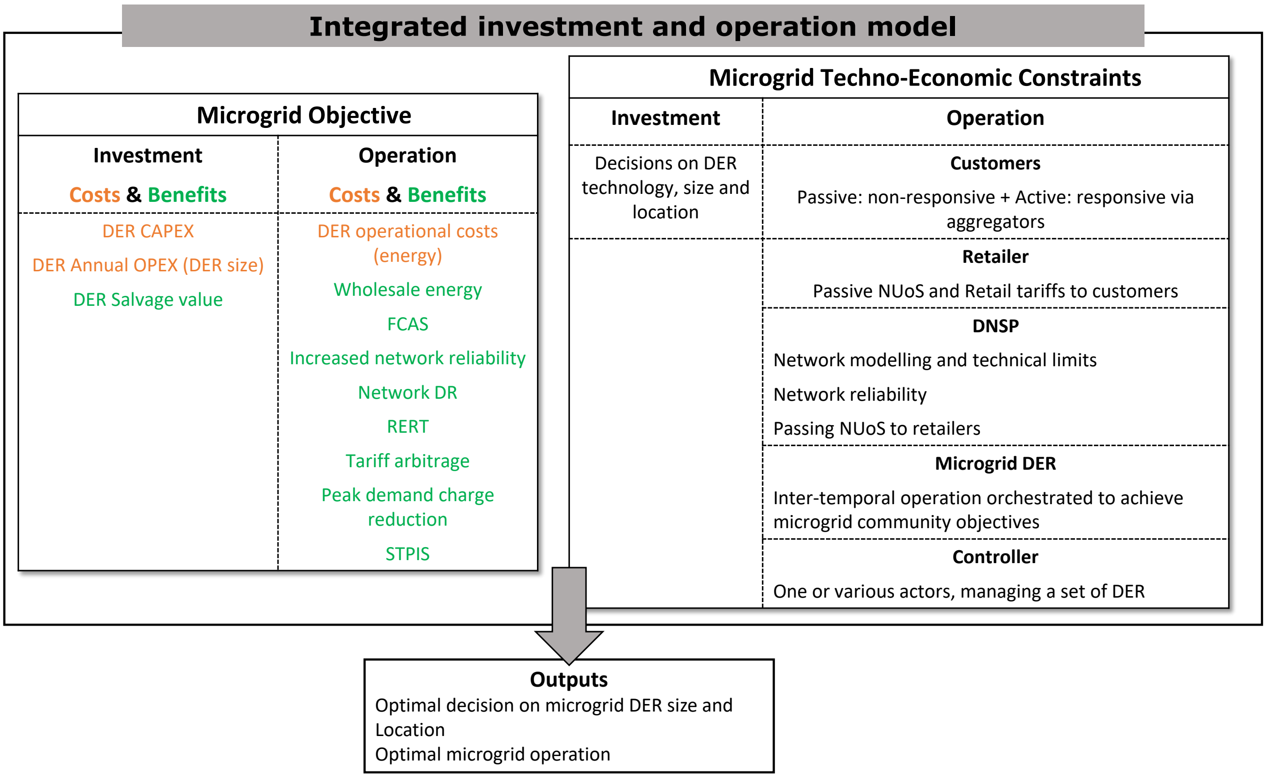


Figure 2. Summary of the different modules in the microgrid integrated investment and operation model

2.3.1 Formulation of the Investment Model

In the following sections, the different modules that comprise the microgrid integrated investment and operation model as presented in Figure 2 will be detailed:

2.3.1.1 Microgrid Objective Module

This module contains the various value streams accessible to the microgrid. Essentially, being an integrated microgrid investment and operation model, this module includes the costs and benefits that arise from the microgrid investment and operation.

First, the relevant investment costs are included. The investment costs for the microgrid DER are a function of the DER size (CAPEX), while also operational costs such as maintenance, associated with the DER size (not the energy output) are considered (OPEX).

The microgrid accrues revenues during its operation by accessing different values streams and depend on the price signals associated with each value stream. For instance, the network charges that customers are subject to are a function of the total energy imported by customers at the MV/LV transformer level multiplied by the Network use of Service (NUoS) charge.

The objective function can be tailored to include different value streams that the microgrid aims to access. The general formulation of the objective of the microgrid is based on the microgrid net cash flows, by adding the different value streams that provide benefits and subtracting the costs of the microgrid investment and operation. In this sense, this module essentially “drives” the optimal investment on microgrid DER and their point of connection within the MV network, so the microgrid as a whole achieves the best outcome in the objective.

Value streams of economic nature that can be accessed by the microgrid operation include (but are not limited to) wholesale energy market arbitrage, frequency control ancillary services (FCAS) participation, provision of network demand response (DR), participation in Reliability and Emergency Reserve Trader (RERT) program, network and retail tariff arbitrage, reduction of peak demand charges, increasing the network reliability and accessing incentives via Service Target Performance Incentive Scheme (STPIS) scheme. Value streams of strategic nature include increasing local renewable generation, provision of local network support, reducing carbon emissions and increasing the microgrid self-sufficiency and resilience (by reducing the expected energy not served (EENS) in case of extreme weather events that result in the microgrid being isolated). It must be noted that the inclusion of the value streams mentioned above is subject to available data.

Additionally, accessing these value streams involves operational costs, that depend on the DER technology and marginal costs ($/MWh) as well as the energy output of the DER technology.

The following relevant assumptions regarding the microgrid objective module and the value streams included are detailed as follows:

- The microgrid acts a single entity that orchestrates all flexible resources (e.g., DER) to maximize the benefits during the span of the economic assessment
- The economic assessment is performed for a duration equal to the DER technology with the shortest lifetime. This is referred as the economic assessment horizon and given the data provided, is equal to 12 years i.e., the battery lifetime;
- The salvage value of the remaining DER assets with longer lifetime than 12 years is included as benefit in the year 12 of the analysis;
- Aligned with the philosophy of the microgrid acting as single entity, the interactions with the upstream grid are measured at the point of connection of the microgrid with the upstream grid. That is, for each single time interval the microgrid as a whole will import energy from the upstream grid to meet local demand (from customers, batteries, EV if any, etc) that will be subject to the wholesale energy market price, or will export energy to the upstream grid, selling that energy according to the wholesale energy market price. In this sense, the losses (if considered in the DNSP module) within the MV network are costs internalized by the microgrid. This means that the microgrid will buy more energy from the wholesale market than the actual local demand, while selling less energy to the wholesale market than the actual local generation.
- The six contingency FCAS markets (delayed/slow/fast for raise and lower services) are considered. Resources that have technical capabilities to participate in these markets will provide availability for the different contingency FCAS markets by leaving some headroom/footroom in their dispatch in case these services are called. The revenues from FCAS are a function of the availability to provide the frequency control service rather than the actual provision of the service. In fact, it is considered that the DER only provide availability (and accrue revenues from this availability) and do not actually deliver FCAS. This assumption is motivated by publicly available AEMO data, which points out that the delivery of frequency control services from the six contingency FCAS markets is required around 1% of the time. However, FCAS availability is required to meet technical constraints (e.g., the model ensures that if FCAS was actually delivered, it must respect the thermal limit of the lines in the MV network and voltage constraints).
- The cost of EENS when an extreme weather event (i.e., bushfire) takes place are calculated using the parametric study carried out for both Donald and Tarnagulla in Project 7. This parametric study provides the EENS for different combination of microgrid DER capacity installed, when the microgrid is not connected to the upstream grid. Whereas the relationship between DER installed capacity and EENS is not strictly linear, an approximation using

hyperplanes is used to represent the impact the different combinations of PV, diesel generator and battery (in kWh) have in the EENS. The value of EENS is then multiplied by the value of customer reliability (VCR)and the probability of a bushfire to take place.

- Previous studies have indicated that ash and smoke from bushfires can reduce PV system output by about 30% [3]. In the main analysis carried out it is assumed that PV system output is unaffected by the ash and smoke from bushfires. However, the impact of ash and smoke will be analysed in Chapter 4 through sensitivity studies.
- The EENS parametric study from Project 7 was performed for each's town current demand and DER penetration. Nevertheless, increased demand conditions will increase the EENS not served in the same bushfire conditions, and customer-owned DER will support microgrid DER, effectively reducing the EENS in the case of a bushfire. In the main analysis carried out it is assumed that increased demand conditions as well as higher penetration of customer-owned DER will result in the same EENS as presented in the parametric study performed in Project 7. Nevertheless, this assumption will be addressed in Chapter 4 through sensitivity studies.
- Microgrid controller costs (CAPEX and OPEX) are not considered in the investment analysis as very limited cost data is found relating microgrid size and controller CAPEX costs. In Section 4.3 controller investment costs (CAPEX) are included for the net present value (NPV) analysis based on average microgrid controller data from the United States [4], as reliable Australian data was not obtained. Operational costs such as maintenance costs (OPEX) for the controller were not available.
- Network investment cost recovery is considered by including the network use of services (NUoS) charges that customers are subject to. Therefore, the underlying assumption is that the DNSP owns the network assets in the microgrid and is in charge of the operation and maintenance of those assets.

Below, three simple equations are presented to illustrate the main terms considered in the microgrid objective module of the investment model, with all terms in ($). First, the annual microgrid net cash flows (NCF) are calculated. Annual microgrid NCF consider the revenues from selling energy to the wholesale market (R_{WS}); the costs from buying energy to the wholesale market (C_{WS}); the revenues from contingency FCAS participation R_{FCAS}; the network use of service costs for the customers, charged at MV/LV transformer level ($C_{NUoS,cust}$); the costs associated with the EENS when extreme weather events take place (C_{EENS}); the microgrid DER CAPEX ($CAPEX_{DER}$) and OPEX ($OPEX_{DER}$) and the salvage value of the PV and diesel generator ($R_{salvage\ value,DER}$) at the end of the horizon of the economic assessment (12 years). It must be noted that the CAPEX of the DER is considered only in the year 0 of the microgrid and the salvage value of the PV and diesel generator are only considered in the last year of the economic assessment (year 12).

Other value streams such as RERT, DR, STPIS have not been included for two main reasons. First, there was not enough data available to have a reasonable degree of certainty on the revenues these value stream could provide. Second the ability of the microgrid to access these value streams is uncertain (e.g., in the last years AEMO has not require RERT from resources in Victoria, it is unclear if Powercor will require DR from the microgrid, and there is not enough granularity in the publicly available reliability data to quantify the possible revenues from the STPIS when the microgrid is in place). Therefore, rather than including these value streams in the microgrid integrated investment and operation model, which will impact the investment decision, studies using the operational model can be carried out to understand the additional revenues coming from these more uncertain value streams.

$$Annual\ Microgrid\ net\ cash\ flows\ (NCF) = R_{WS} - C_{WS} + R_{FCAS} - C_{NUoS,cust} - C_{EENS} - CAPEX_{DER} - OPEX_{DER} + R_{salvage\ value,DER}$$

The annual microgrid NCF for each year of the economic assessment are then transformed in discounted cash flows (DCF) to account for the "time value of money" during the lifetime of the microgrid. This is quantified considering the discount rate r, and the year t in which the net cash flows were accrued

$$DCF_t = \frac{NCF_t}{(1+r)^t}$$

Finally, the net present value (NPV) of the project can be calculated, as the sum of the DCF during the horizon of the economic assessment. The optimal investment decisions aim to maximize this NPV.

$$NPV = \sum_{t=0}^{T} DCF_t$$

2.3.1.2 Customer Module

This module contains the techno-economic constraints to model the customers in the microgrid. The main constraints in this module are the following:

- Customer demand, aggregated at MV/LV must be met under normal operation (i.e., not during extreme weather event conditions)
- Customer-owned DER is aggregated at the MV/LV transformer.
- There is the possibility to include flexible customer-owned resources (e.g., DER). Their operation can be orchestrated according to the community objective function via aggregators. Active customers exports are managed by the aggregator, only limited by the actual voltage and thermal constraints in the network and operated according to the microgrid objective function.
- Flexible customer-owned resources operation is modelled to access the same value streams than the microgrid DER if the technical capabilities allow (e.g., activation time, duration of service, etc.).
- PV generation is modelled using normalized PV profiles from the smart meter data in Project 7 and then scaled in the different scenarios depending on the PV systems installed at each MV/LV transformer. The actual PV generation of all customer-owned resources can be curtailed as to guarantee that the network statutory limits are met.
- Converter-interfaced customer-owned resources that can provide reactive power support (i.e., flexible customer-owned resources managed by an aggregator) are modelled using a linear approximation of the relationship between apparent power, reactive power and active power.
- There is the possibility to include DER that are not managed by aggregators, operated with the usual ‘off-the-shelf’ control to maximise self-consumption while being subject to static export limits (5 kW per PV system in place in the MV/LV transformer).

2.3.1.3 DNSP Module

This module contains the technical constraints to model the microgrid MV network, effectively representing the role of the DNSP. The main constraints in this module are the following:

- A lossless linear formulation of the optimal power flow (OPF) that can represent the operation of the three-phase balanced MV distribution network with an adequate accuracy for the investment problem [5].
- Voltage at the different buses of the network is constrained to remain within the ±5% range of the nominal voltage.
- Linear approximation of active and reactive power flows as well as thermal limits of the MV/LV transformers and lines.
- Local network support from the microgrid DER and flexible customer-owned resources can be procured by the DNSP to manage the thermal and voltage constraints in the network to improve the resulting optimal microgrid operation according to the objective function.

2.3.1.4 Controller Module

This module serves the function of controlling the flexible customer-owned resources as well as the microgrid DER. It essentially maps which resources in the microgrid can be controlled to follow the microgrid objective.

2.3.1.5 Retailer Module

This module includes the techno-economic constraints that represent the role of a retailer in the microgrid. The main constraints in this module are the following:

- A flexible formulation of different retail tariff options that allows locational and time granularity, potentially allowing for different retail offers to different customers within the microgrid.
- A flexible formulation of network tariff options that are passed down to customers via the retailer. It allows to include network charges both in terms of usage as well as peak demand. Like the retail tariff it allows locational and time granularity with the possibility to test different network tariff options, such as a peak demand charge for the whole microgrid and local use of service charges.

2.3.1.6 Investment in Microgrid DER Module

In this module the investment decision on the different DER technologies is modelled using the following techno-economic constraints:

- The microgrid DER can be connected to the LV side of the MV/LV transformers (close to customers, to meet their load and provide local network support) or at the interface of the microgrid with the upstream grid (to minimize power flows and losses in the community and participate in system-level markets). There is no limit on the number of microgrid DER that can be connected in the system.
- The investment costs are a function of technology-specific costs as well as the DER size. To avoid the use of binary variables, fixed costs are internalized in the size-dependent cost. This is done ex-post a first test of the investment model, when a proxy of DER sizes is known.
- The annual operational costs of each technology as a function of the DER size.
- Marginal costs ($/MWh) of each microgrid DER.

The selected portfolio of DER according to this module will then affect the ability to access value streams and accrue revenues with the microgrid operation during its lifetime.

2.3.1.7 Operation of Microgrid DER Module

In this module the operation of the microgrid DER is modelled using the following techno-economic constraints:

- Inter-temporal operation of microgrid DER, subject to its technical limits which are a function of the investment size. Technical limits included are maximum and minimum generation, efficiency, ramp rates and response times.
- In the case of the battery, there is an additional term related to battery capacity. The inter-temporal relationship between energy stored, charge and discharge is considered.
- In the case of PV, normalized PV generation profiles based on Project 7 smart meter data are utilized to model the maximum available PV generation at different times.
- The ability of these resources to participate in different markets and access different value streams according to their technical limits. The need to reserve energy footroom and headroom for the provision of different value streams (e.g., FCAS) is considered.
- Converter-interfaced DER are modelled using a linear approximation of the relationship between apparent power, reactive power, and active power.

2.3.2 Main Modelling Assumptions

The modelling detailed in this section has some underlying assumptions, that have been discussed in each microgrid investment module. This section provides a list of the main modelling assumptions:

- All the flexible resources in the microgrid (e.g., microgrid DER, flexible customer-owned DER) are orchestrated to achieve the best outcome in the aggregate, considering the microgrid as a single entity (i.e., maximizing the lifetime benefits from the microgrid according to the objective of the microgrid)

- RERT, STPIS and DR are potential value streams that the microgrid could access, however they are not considered in the microgrid integrated investment and operation model. This is due to limited data both regarding the actual ability of the microgrid to access these value streams (e.g., RERT has not been required in Victoria in recent years; it is unclear if DR is a preferred option to address peak demand periods) as well as the price signals that would be associated with these value streams.
- The cost impact of extreme weather events is included in the investment microgrid model, with an approximation using hyperplanes based on the parametric study presented in Project 7. Hyperplanes allow to represent the impact of different DER installed capacity on the EENS, and with the VCR, the cost associated with resilience can be quantified. Only the EENS in an off-grid scenario where a bushfire that does not cause fuel disruption is considered, as by Project 7 this was the kind of bushfire most likely to take place. Further sensitivity studies on the type of bushfire are presented in Chapter 4.
- The six contingency FCAS markets (delayed/slow/fast for raise and lower services) are considered. Resources that have technical capabilities to participate in these markets will provide availability for the different contingency FCAS markets by leaving some headroom/footroom in their dispatch in case these services are called. The revenues from FCAS are a function of the availability to provide the frequency control service rather than the actual provision of the service. In fact, it is considered that the DER only provide availability (and accrue revenues from this availability) and do not actually deliver FCAS. This assumption is motivated by publicly available AEMO data, which points out that the delivery of frequency control services from the six contingency FCAS markets is required around 1% of the time.
- The MV network of each community is modelled as a three-phase balanced network, with a lossless linear approximation of the OPF.
- Customer demand and customer-owned DER are aggregated to MV/LV level.
- All the flexible resources in the microgrid (e.g., microgrid DER, flexible customer-owned DER) will provide local network support to achieve the best outcome for the microgrid according to its objective.
- Microgrid DER can be located either at the point of connection of the community with the upstream grid or at the LV side of the MV/LV transformers. There is no limit in the number of microgrid DER that can be installed. It must be noted this is a decision related to the project, rather than a modelling limitation. All buses could potentially have DER connected, but it is assumed that the most likely locations are either next to customers, to meet local demand or close to the upstream grid to participate in system-level markets. In turn, by limiting DER locations we achieve a reduction in the optimisation problem size.
- The investment costs are a function of technology-specific costs as well as the DER size. To avoid the use of binary variables, fixed costs are internalized in the size-dependent cost. This is done ex-post a first run of the investment model, when a proxy of DER sizes is known.
- Converter-interfaced microgrid DER and customer-owned DER are modelled using a linear approximation of the relationship between apparent power, reactive power, and active power.
- Network investment cost recovery is considered by including the network use of services (NUoS) charges that customers are subject to. Therefore, the underlying assumption is that the DNSP owns the network assets in the microgrid and is in charge of the operation and maintenance of those assets.

2.4 Microgrid Operational Model: Model overview

The microgrid operational model is based on a centralized multi-period optimization problem formulated using second-order cone (SOC) programming. The purpose of this model is to obtain the resulting microgrid operation and economic performance during the economic assessment horizon. In the context of microgrid economic assessment, the operational model should include the energy, flexibility services and cash flows exchanged among the different actors within the microgrid and the actors outside the microgrid, as well as the operation within the microgrid. The microgrid operational model orchestrates all the flexible resources within the microgrid (i.e., microgrid DER, customer-owned DER) according to the microgrid objective (e.g., maximize revenues, maximize self-sufficiency) while considering all technical limits (e.g., network capacity and voltages, DER size). To this end, the operational model accurately models DER and distribution network operation, yielding operational results (e.g., DER setpoints, energy exchange between the microgrid and the upstream grid, peak demand of the microgrid) given the local demand, local generation, system-level markets and flexibility services prices and the microgrid objective.

In the microgrid operational model the optimisation problem is comprised of an objective function, that drives the microgrid orchestration and operation of resources, and techno-economic constraints that ensure the objective function is optimized while guaranteeing technical and, potentially, contractual limits. Figure 3 presents a schematic summary of the different modules, accompanied with a brief description of each module:

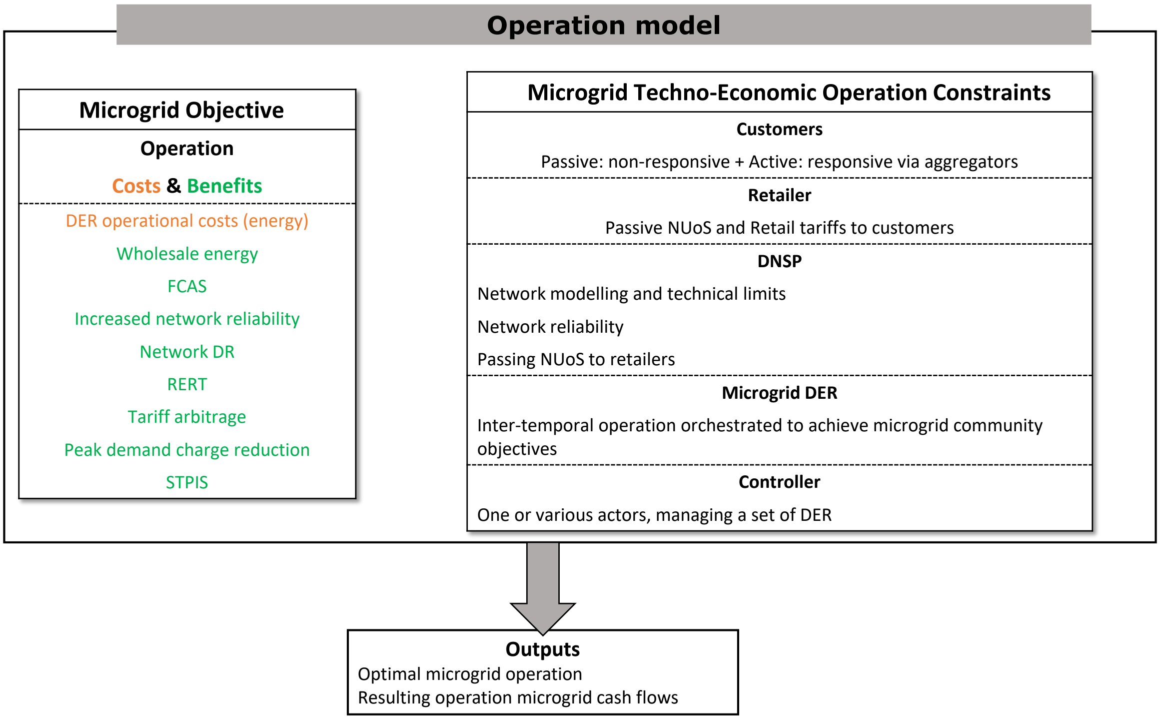


Figure 3. Summary of the different modules in the microgrid operational model

2.4.1 Formulation of the Operational Model

The operational model the microgrid DER size and location are inputs coming from the investment model. This allows to include further detail in the microgrid operation modelling. While the main features of the microgrid integrated investment and operation model are directly transferrable to the microgrid operational model, there are several relevant modifications. In the following sections the modifications in the different modules will be detailed:

2.4.1.1 Microgrid Objective Module

The general description of the microgrid objective module presented in Section 2.3.1.1 can be conveyed in the microgrid operational model with the following distinctions:

- The CAPEX and size dependent OPEX of the microgrid DER is not included.
- The microgrid operational model focuses on *normal operation* (i.e., not the microgrid operation during extreme weather events). Therefore, the cost of EENS is not included.
- The microgrid operational model calculates the NCF for a given time frame (e.g., one month during the first year of the project). Since the operational model does not do a lifetime analysis to select an investment DCF are not included in the objective function. The NPV of the microgrid is calculated ex-post once all the annual NCF coming from operation of the microgrid during its lifetime are available.
- In specific case studies further value streams not considered in the microgrid integrated investment and operation model might be studied, such as DR, or different NUoS charges

structures. The addition of this value streams in the NCF will follow the same structure than the one presented in Section 2.3.1.1.

2.4.1.2 Customer Module

The general description of the microgrid objective module presented in Section 2.3.1.2 can be conveyed in the microgrid operational model with the following distinctions:

- Converter-interfaced customer-owned resources that can provide reactive power support (i.e., flexible customer-owned resources managed by an aggregator) are accurately modelled using the quadratic relationship between apparent power, reactive power and active power.

2.4.1.3 DNSP Module

The general description of the microgrid objective module presented in Section 2.3.1.3 can be conveyed in the microgrid operational model with the following distinctions:

- A SOC relaxation of the OPF is used. This power flow model can represent with accuracy the operation of the three-phase balanced MV distribution network in radial networks such as the ones in Donald and Tarnagulla [6].
- Current, and therefore, losses in the microgrid MV network are considered.
- Voltage at the different buses of the network is constrained to remain within the ±5% range of the nominal voltage.
- An accurate model of active and reactive power flows and thermal limits of the MV/LV transformers and lines are achieved using a quadratic formulation.

2.4.1.4 Controller Module

The formulation of this module in the microgrid operational model is the same as in the microgrid investment problem presented in Section 2.3.1.4.

2.4.1.5 Retailer Module

The formulation of this module in the microgrid operational model is the same as in the microgrid investment problem presented in 2.3.1.5.

2.4.1.6 Investment in Microgrid DER Module

The DER investment size and location are an input in the microgrid operational model, and thus this module is not included.

2.4.1.7 Operation of Microgrid DER Module

The general description of the microgrid objective module presented in Section 2.3.1.7 can be conveyed in the microgrid operational model with the following distinctions:

- Converter-interfaced DER that are accurately modelled using the quadratic relationship between apparent power, reactive power and active power.

2.4.2 Main Modelling Assumptions

The modelling detailed in this section has some underlying assumptions, that have been discussed in each microgrid investment module. This section provides a list of the main modelling assumptions:

- All the flexible resources in the microgrid (e.g., microgrid DER, flexible customer-owned DER) are orchestrated to achieve the best outcome in the aggregate, considering the microgrid as a single entity (i.e., maximizing the lifetime benefits from the microgrid according to the objective of the microgrid)

- The DER investment size and location are an input in the microgrid operational model.
- The MV network of each community is modelled as a three-phase balanced network, using a SOC approximation of the OPF, which allows to include active and reactive power flows, voltage, current and losses in the MV network.
- Customer demand and customer-owned DER are aggregated to MV/LV level.
- All the flexible resources in the microgrid (e.g., microgrid DER, flexible customer-owned DER) will provide local network support to achieve the best outcome for the microgrid according to its objective. The six contingency FCAS markets (delayed/slow/fast for raise and lower services) are considered. Resources that have technical capabilities to participate in these markets will provide availability for the different contingency FCAS markets by leaving some headroom/footroom in their dispatch in case these services are called. The revenues from FCAS are a function of the availability to provide the frequency control service rather than the actual provision of the service. In fact, it is considered that the DER only provide availability (and accrue revenues from this availability) and do not actually deliver FCAS. This assumption is motivated by publicly available AEMO data, which points out that the delivery of frequency control services from the six contingency FCAS markets is required around 1% of the time.
- Previous studies have indicated that ash and smoke from bushfires can reduce PV system output by about 30% [3]. In the main analysis carried out it is assumed that PV system output is unaffected by the ash and smoke from bushfires. However, the impact of ash and smoke will be analysed in Chapter 4 through sensitivity studies.
- Network investment cost recovery is considered by including the network use of services (NUoS) charges that customers are subject to. Therefore, the underlying assumption is that the DNSP owns the network assets in the microgrid and is in charge of the operation and maintenance of those assets.

3 Techno-Economic Framework Inputs

The main objective of this work is to understand how future system-level and community conditions will impact the investment in DER to form the microgrid, the microgrid operation, and the value the microgrid can provide to the different stakeholders.

Future system-level and community conditions in the techno-economic framework are parameters with uncertain development during the lifetime of the microgrid (e.g., in the next 12 years). To understand the impact of different future conditions, the approach selected is the generation of various scenarios that represent credible future system-level and community developments. Moreover, within the set of credible future scenarios, the scenarios are selected to represent “boundary conditions”. That is for each uncertain parameter, the scenarios selected represent two opposite realisations of the uncertainty. For instance, rather than selecting four scenarios with increasing wholesale market prices and increasing volatility in prices, this approach would select only two scenarios: the lowest prices with the lowest volatility, and the highest prices with the highest volatility. With this approach of selecting scenarios, the motivation is not to be correct about the future development of uncertain parameters, but rather understand the sensitivity of the microgrid investment, operation and value generated under considerably different conditions. The main uncertain parameters that will impact the microgrid, and the scenarios selected and assumptions when developing these scenarios for each uncertain parameter are detailed in Section 3.1.

When studying the investment and operation of a microgrid, an adequate time granularity must be selected. The time granularity must be able to capture system-level conditions such as daily price profiles, price spikes, and the relationship between prices of different competing value streams (e.g., wholesale market and contingency FCAS). Moreover, local PV generation, demand and the constraints in the MV network will impact the ability of the microgrid DER to participate in system-level markets and provide value, so they also need to be captured with adequate time granularity. Therefore, the operation of the microgrid is modelled with a 30-minute granularity, for both the investment and operation problems. This time granularity is selected as it can represent the relevant system-level and local conditions and aligns with the smart meter data available from Project 7. However, studying the investment and operation problems for the economic assessment horizon (12 years) with 30-minute granularity would be a computationally expensive task (consisting of 210240 time-steps to represent the microgrid inter-temporal operation). In addition to this, during a year in the economic assessment horizon, each season tends to present days with similar market prices, demand and local generation conditions that will have similar impact on investment decisions and will result in similar value provided by the microgrid operation. Therefore, data analysis is used to create design days and months for the investment and operational model, respectively. The methodology to generate this design days and months is detailed in Section 3.2.

Additional techno-economic data is required to model the operation of the microgrid. In terms of technical data, the MV network of each town (Donald and Tarnagulla) is required to understand the local constraints that might arise, limiting the value the microgrid DER can provide, while also allowing to find the optimal location of the microgrid DER. The MV network of each town, as well as the current customer-owned DER and demand were provided by Project 5 and Project 7, and are presented in Section 3.3.

The decision to invest in DER will be impacted by the investment and operational costs as well as technical constraints for each technology. These inputs are detailed in Section 3.4

Finally, the different roles and actors involved in the microgrid are detailed in Chapter 5.

3.1 Scenarios

To assess the economic performance and possible risks through the lifetime of the microgrid developing a set of future scenarios is of paramount importance. In a microgrid environment, future market prices, community-driven changes (e.g., customer adoption of technologies and customer demand development) and weather (including low probability/high risk events such as bushfires or floods) are four main sources of uncertainty with a material impact on the microgrid operation. By generating scenarios within the proposed framework, the microgrid operation and economic performance can be studied and analysed for different conditions in the future. Therefore, expected benefits and costs during the economic assessment horizon can be assessed.

3.1.1 Community-driven scenarios and assumptions

Customers within the community might change their energy usage habits during the lifetime of the microgrid. This can have an impact on the microgrid operation, with possible synergies arising between customer-owned DER and microgrid DER. Given that the location of the microgrids is known (Donald and Tarnagulla towns in Victoria) and significant variations on community-driven changes can arise in different locations, a survey was sent out to the community. This survey seeks to aid the generation of community-driven scenarios, informing on the community position regarding:

- Customer adoption of DER technologies (PV, batteries);
- Customer interest towards aggregators controlling their DER for economic benefits;
- Customer adoption of new more dynamic retail and network tariffs;
- Customer adoption of EV;
- Customer interest on participating in community initiatives (e.g., community batteries).

3.1.1.1 Survey Responses

The survey did not have a large participation, with only eleven responses, and the statistical significance of the survey is therefore very limited. The lack of responses can infer that the interest in energy projects within the community is limited. However, the received responses can still provide valuable insights regarding the most engaged members of the community. Figure 4 shows the location all the responses received in the survey.

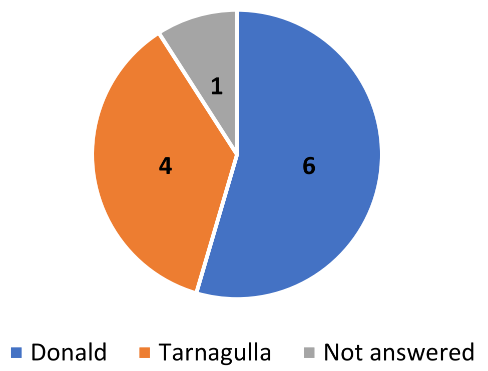


Figure 4. Location of the survey responses

The first part of the survey focused on the customer adoption of DER technologies. Results in Figure 5 display similar trends to the general Australian landscape regarding adoption of PV and battery systems. According to the survey, it would be expected a higher and earlier uptake of PV systems in the community, whereas not all respondents are planning to install battery systems and among those who plan to install battery systems in their business or residence, are looking to install them in the next 5 to 10 years rather than in the short term (next 5 years). When respondents were asked about their interest on participating in aggregator portfolios, where their DER would be controlled to participate in different markets resulting in economic benefits, responses displayed a positive attitude. Figure 6 displays most respondents are very interested or interested in participating in these kinds of schemes, with no responses showing significant reservations towards the role of aggregators. This also informs that possibly more engaged customers are more open to undertake a proactive attitude with their PV and battery systems, highlighting the importance of engaging the residents of Donald and Tarnagulla to achieve the best outcome of their communities. Therefore, in the modelling the main scenario assumes that customers' DER are orchestrated with the microgrid DER to achieve the best outcome for the community (i.e., maximizing benefits).

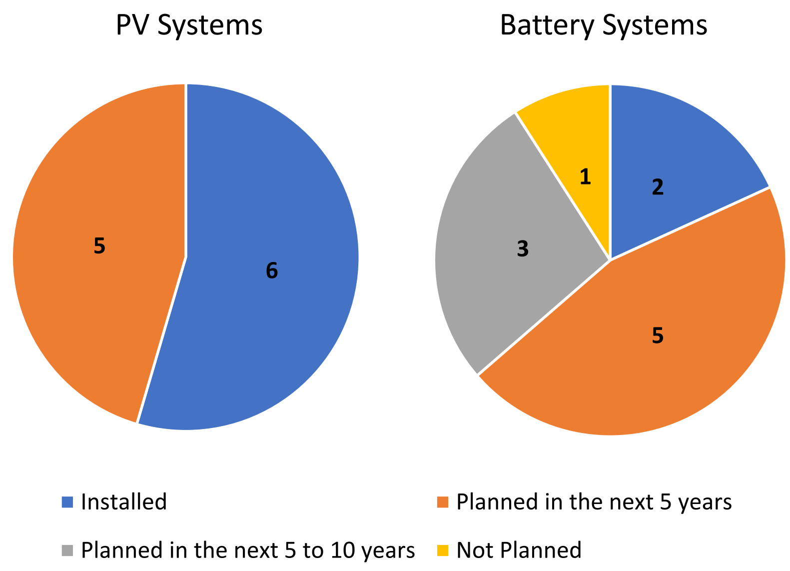


Figure 5. Survey responses on customer adoption of DER technologies

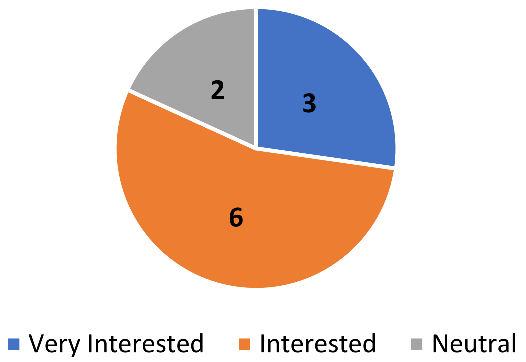


Figure 6. Survey responses on customer preference towards aggregators managing their DER for economic benefits

When asked about tariffs, Figure 7 shows that a majority of respondents preferred flexible price tariffs. Therefore, the assumption in the modelling is that customers are subject to time-of-use tariffs, both in terms of network and retail tariffs.

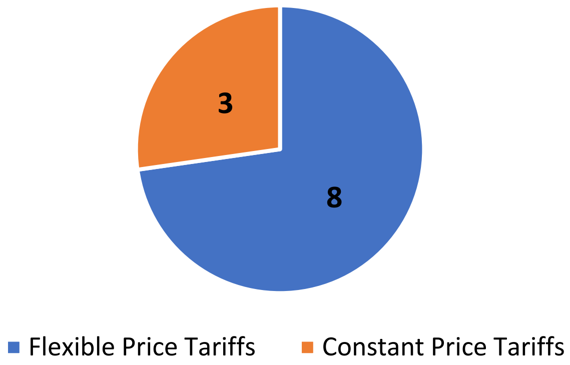


Figure 7. Survey responses on customer preference towards different kind of tariffs

Regarding EV uptake, the results from the survey in Figure 8 display there is a limited interest in the community. Most respondents are not planning to purchase an EV, and considering these respondents are likely to be the most engaged and early adopters of low-carbon technologies, it can be inferred EV uptake will be minimal within the community during the economic assessment span. Another issue with EV adoption is charging location. Even if EV uptake is relatively low, if most EV owners use public charging, the MV/LV transformer corresponding to the EV public charging location might display significant demand coming from EV charging. When asked about preferences on charging location, respondents were allowed to provide multiple answers. Figure 9 shows that almost all respondents considered charging their EV at home their preferred option. Broader surveys in Australia [7] have displayed the same kind of preferences. This is further supported by the very diverse responses regarding the importance of public available charging presented in Figure 10.

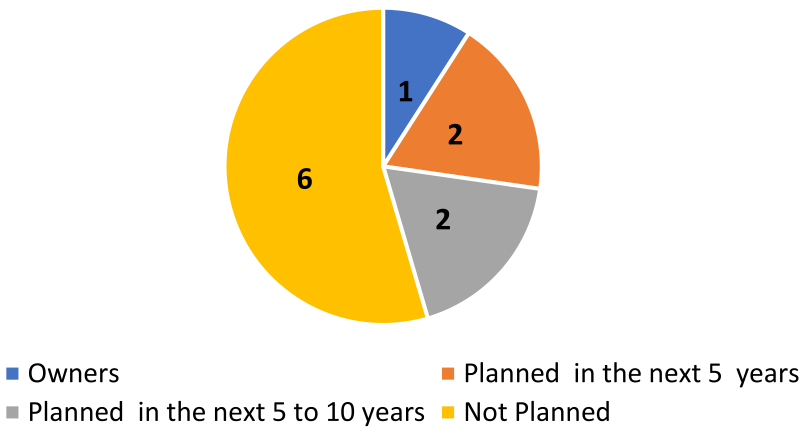


Figure 8. Survey responses on customer adoption of EV.

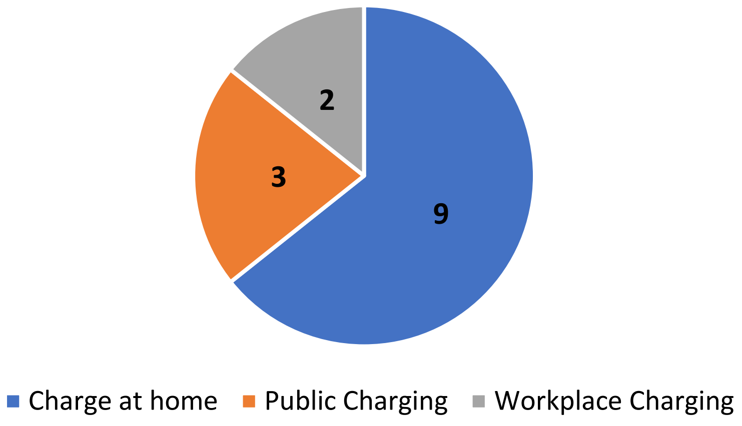


Figure 9. Survey responses on EV charging location.

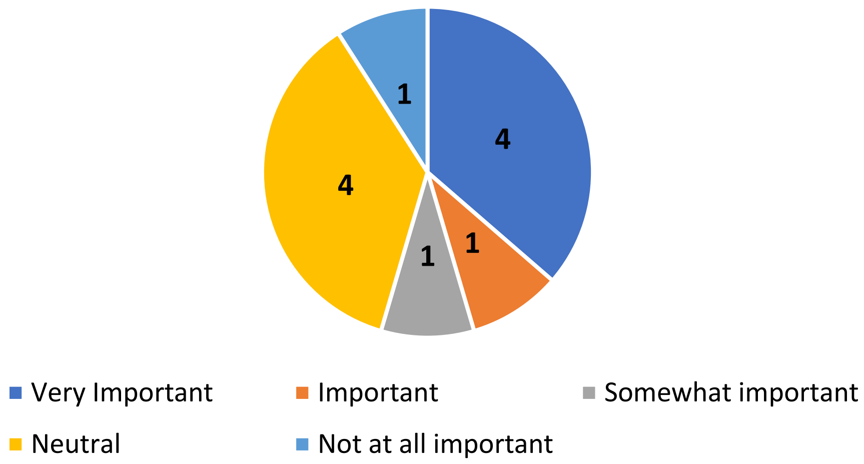


Figure 10. Survey responses on the importance of public EV charging.

The last section of the survey focused on the interest of respondents to participate in different community initiatives, which imply the drive of respondents to be more proactive actors on the microgrid landscape. The survey asked if respondents would be interested on being part of community initiatives, such as community-shared resources, were the participants could “lease” a portion of a resource and benefit from the revenues accrued by this resource in the different markets. Figure 11 displays a general positive attitude from the respondents, and therefore a commercial business case that could be of interest for the community. Additionally, the survey asked how important is for the respondent to consider environmental aspects in energy projects within the community. Figure 12 displays diverse responses, although for almost half of the respondents it was important or very important to consider environmental aspects even if it came with an additional cost. While the responses do not provide a definite position from the community, they do display there is some value of exploring the cost of including environmental aspects in the microgrid integrated investment and operation model.

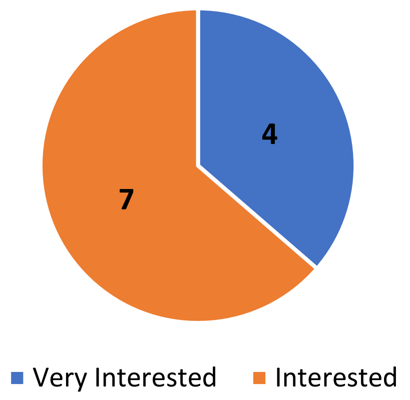


Figure 11. Survey responses on interest in participating in community initiatives

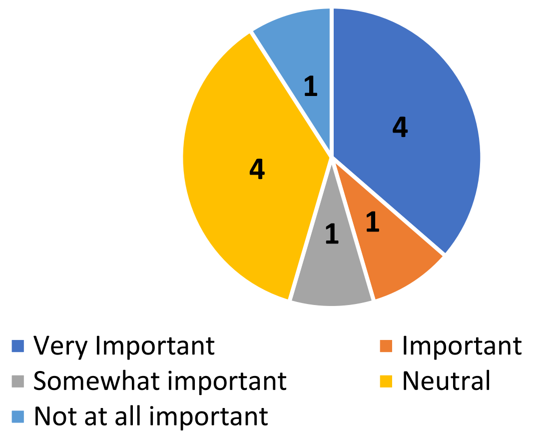


Figure 12. Survey responses on the importance of considering environmental aspects when building the microgrid

3.1.1.2 Inclusion of survey responses in customer-driven scenarios

As previously discussed, the statistical significance of the survey is limited due to the reduced number of survey responses received (11 responses). When including the responses of the survey in the modelling of customer-driven scenarios, it is assumed that the respondents of this survey are engaged, likely to be highly interested in energy projects and probably early adopters of new low-carbon technologies and advancements in the energy sector. Therefore, following the diffusion of innovations model [8] their responses are likely to reflect the preferences of the early adopters (13.5% of the members of the community) or early majority (34% of the members of the community), and in general cannot be assumed for the vast majority of customers in Donald and Tarnagulla. However, the responses are included in the modelling as follows:

- A scenario is generated where PV and battery systems uptake are assumed to follow the general trends of Australia, which are reflected in the responses showing a more rapid uptake of PV systems and a lower and incremental uptake of battery systems.
- Within the customers that own PV and/or battery systems, there is an interest in participation in aggregator portfolios, where their DER are managed to participate in different markets and services. Therefore, customer-owned resources are assumed to be controlled by third party (such as aggregator, community retailer, community operator) and are orchestrated with the microgrid DER to maximize the benefits accrued by the community as a whole. The main assumption behind this modelling approach is that with relevant efforts on education and engagement of customers, DER owners will have a positive attitude towards participating in aggregator portfolios.

- A residential time-of-use network tariff is assumed for all customers in both Donald and Tarnagulla.
- The expected EV uptake is limited during the lifetime of the microgrid, and it will not probably be a driver of microgrid investment. If the EV impact were to be considered, both Australia-wide surveys as well as this survey pointed out a preference towards home charging. Therefore, EV charging demand should be assumed to be equal among the different MV/LV transformers occurring during the evening, at the time the EV owner returns home from work.
- There could be an interest from the community to consider environmental aspects when investing in the microgrid. Therefore, it is worth to analyse the impact environmental considerations will have in the optimal investment in the microgrid. However, there is not available data, especially in terms of the carbon intensity in the energy purchased from the grid, to carry out a comprehensive analysis of environmental aspects. Therefore, environmental aspects can be considered by comparing the investment decisions, costs and benefits that arise by not allowing investment on DER that require fossil fuels (e.g., diesel generators).

3.1.1.3 Customer adoption of DER technologies scenarios

Given the results of the survey and their statistical significance, two scenarios for customer adoption of DER technologies are generated. The motivation of these scenarios is to explore the impact of customer-owned DER in the investment and operation of the microgrid.

- Business as usual (BAU): no new installations of DER (e.g. PV and battery systems) in each town. The currently installed DER remain in place during the lifetime of the microgrid.
- Increased DER: the number of DER (e.g., PV and battery systems) PV penetration reaches 50% in each town whereas the battery penetration reaches 25% in each town.

To create these scenarios the first step required to estimate the number of PV systems currently installed in each town.

- First, the annual maximum PV generation (in kW) at each MV/LV transformer was extracted from the smart meter data provided by Project 7.
- To calculate the number of PV systems connected at each transformer, it was assumed that all PV systems follow the average size of PV installations in Australia equal to 7kW [9].
- By dividing the PV maximum generation by the average size, the number of PV systems at each MV/LV transformer can be obtained. It must be noted that when the number of PV systems in one MV/LV transformer was not a natural number, it was rounded up to account for the efficiency of PV systems. The resulting number of PV systems aggregated for each town is presented in Table 1.

To calculate the PV penetration as the number of customers with installed PV systems with respect to the total number of customers, the total number of customers in each town needs to be estimated. This was done using the mapping of smart meter data to transformers carried out in Project 7.

- Given that Project 7 had a total of 109 NMI mapped to four of the nine MV/LV transformers in Tarnagulla, and assuming that all transformers had an equal amount of customers connected, the average number of customers in each MV/LV transformer was calculated, as it can be seen in Table 1.
- Given that average number of customers per MV/LV transformers, the total number of customers in Tarnagulla was estimated to 243.
- With the estimated number of PV systems and estimated number of customers, the PV penetration in Tarnagulla can be estimated to 12.3%.
- This process was also carried out in Donald, following the data from Project 7 in which had 820 NMI mapped to twenty-six MV/LV transformer, and extrapolating the average number of customers per transformer to the forty MV/LV transformers in Donald, total number of customers and PV penetration can be estimated.

Table 1. Annual maximum PV generation from Project 7 and estimated number of PV systems in each town

Location	Estimated number of PV systems (2020)	Average number of customers per transformer	Total estimated number of customers	Estimated current PV penetration (%)
Tarnagulla	30	28	243	12.3
Donald	97	32	1280	7.6

In the BAU scenario, the PV systems installed in each town remain constant for the horizon of the economic assessment. It is also assumed no customer-owned battery systems are installed in each town, coming from the assumptions carried out in Project 7.

In the scenario of increased DER, the estimated number of PV systems increases linearly until reaching 50% penetration, whereas battery systems increase linearly reaching 25% penetration in each town. This is aligned with the survey responses that pointed out to lower uptake of battery systems with respect to PV systems as well as with forecasts at national level [10]. The PV penetration evolution in each town during the horizon of the economic assessment is presented in Figure 13 while the battery penetration evolution in each town is presented in Figure 14. Each battery system installed in the microgrid is assumed to follow the specifications of Tesla Powerwall: 5kW/13.5kWh [11]. In terms of allocation of new customer-owned DER to MV/LV transformers, new resources are allocated equally among MV/LV transformers for both PV systems and battery systems.

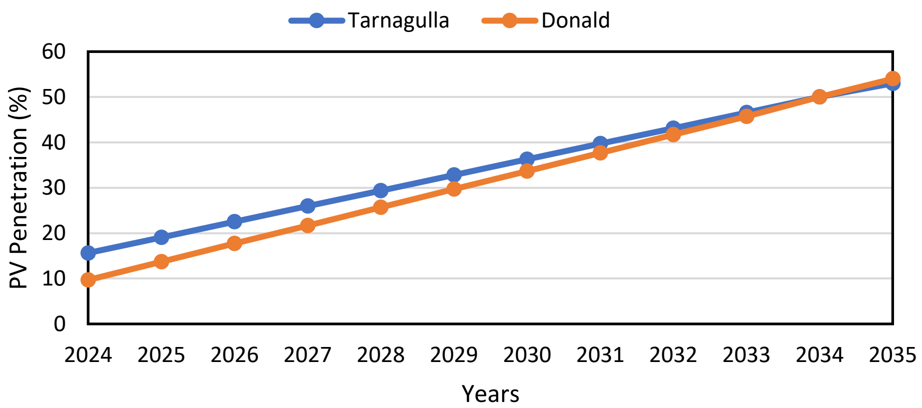


Figure 13. PV penetration evolution for Donald and Tarnagulla in the increase DER scenario

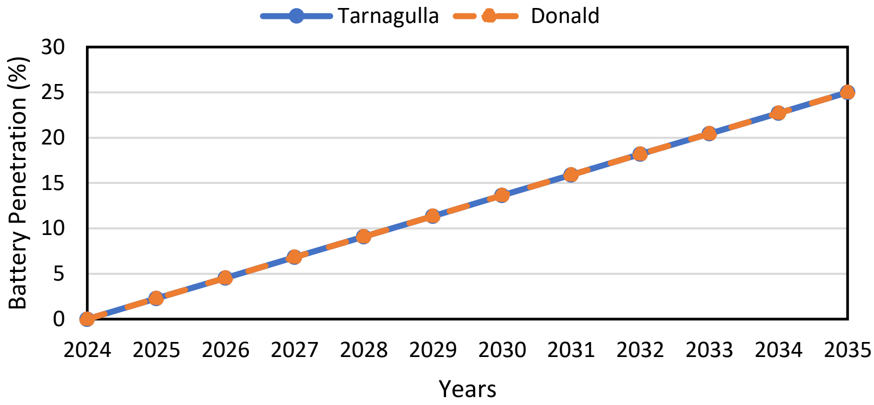


Figure 14. Battery penetration evolution for Donald and Tarnagulla in the increase DER scenario

3.1.1.4 Community Demand Scenarios

In addition to the community adoption of DER technologies, the evolution of customer demand throughout the economic assessment will have an impact on the microgrid operation and ability to accrue revenues. To this end, two customer demand scenarios are generated. Assuming the microgrid will be in place from the year 2024, there is publicly available peak load forecasts generated by Powercor in the 2021 Distribution Annual Planning Report (DAPR) during the period spanning from 2024 to 2026. Moreover, the peak load forecasts for the Bendigo terminal station are broken down by feeder, where the 50% probability of exceedance (PoE) forecasted peak demand for CTN is applied to Donald and the 50% PoE forecasted peak demand for MRO is applied to Tarnagulla. Powercor's forecasted load is divided by the current load (year 2021), to generate a factor of growth in per unit. Then, the 30-min smart meter demand (in MVA) of each town is scaled using the factor of growth in CTN and MRO, respectively. From 2024 to 2026 both community demand scenarios generated are assumed to follow Powercor forecasts. From 2026 to the end of the economic assessment two demand scenarios are generated as follows:

- Business as usual (BAU) demand: the demand in each town remains constant from 2026 onwards;
- High demand: customer demand steadily increases with the same factor of growth each year. The factor of growth applied to each town is equal to the average year-to-year growth calculated using Powercor forecasts from 2022 to 2026.

The motivation behind the generation of these two customer demand scenarios is to understand the microgrid operation under two differentiated conditions (e.g., increasing customer demand and a constant demand) and discern the value the microgrid can provide in both conditions, rather than provide an accurate load forecast.

The peak demand in per unit (calculated with respect to the peak demand during 2021) for each scenario during the lifetime of the microgrid is presented for Donald in Figure 15 and for Tarnagulla Figure 16

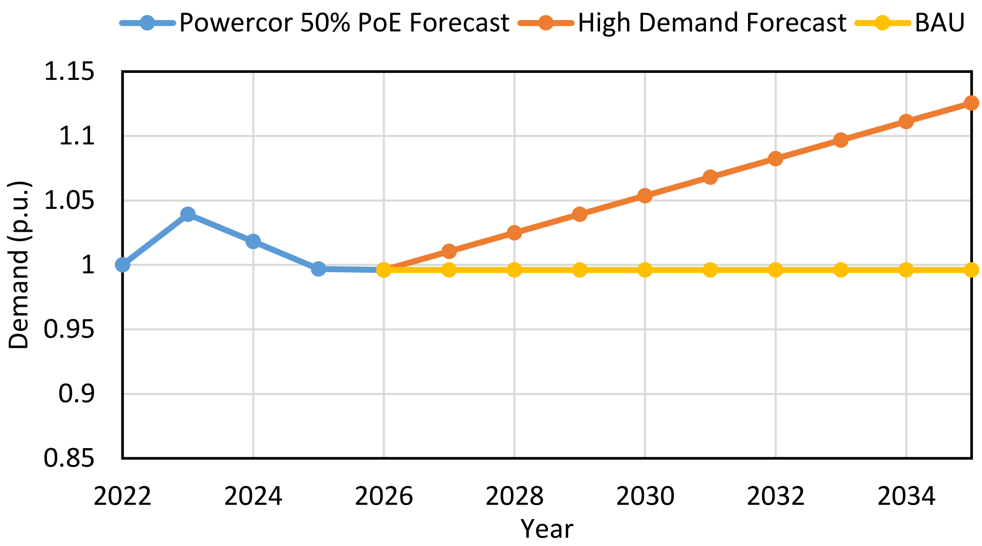


Figure 15. Evolution of demand scenarios for Donald (in per unit using as a base the peak demand in 2021)

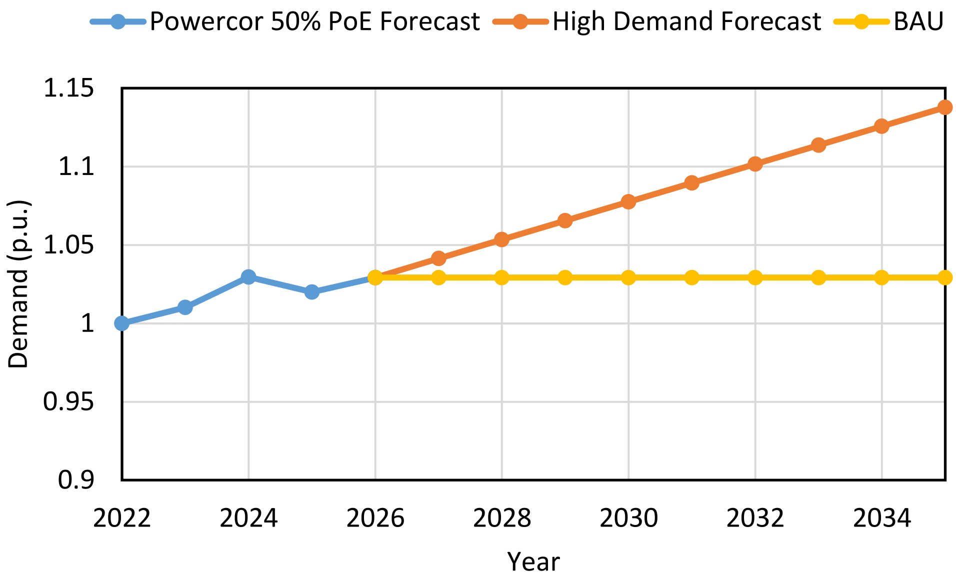


Figure 16. Evolution of demand scenarios for Tarnagulla (in per unit using as a base the peak demand in 2021)

3.1.2 Weather scenarios and assumptions

Weather scenarios can impact the microgrid operation and economic performance. During normal operation solar irradiance will have an impact on the local generation produced by consumer-owned PV systems as well as the microgrid PV system. Moreover, as discussed thoroughly in Project 7, extreme weather event such as bushfires and floods are high impact low probability events that affect the resilience of the network, where the expected energy not served and VCR will impact the investment decision on the microgrid DER

3.1.2.1 Yearly solar irradiance

To generate scenarios of yearly solar irradiance, five years of historical data were retrieved from [12] for the weather station installed in Bendigo. Figure 17 displays a box and whisker plot that allows to visualize the data variability for daily solar radiation each month during the years 2017 to 2021. The results display that the daily solar radiation for each month during the five years of study have low variability, with most data grouped in the median and minimal outliers. This data analysis on the available historical data does not support the need to generate different scenarios of solar radiation, as there are no significant differences through years.

Therefore, a single scenario is selected as an input for the investment and microgrid framework. This scenario assumes that the solar radiation captured by the smart meter data provided in Project 7 is constant throughout the economic assessment horizon. It must be noted that, while the solar radiation will be constant, the PV generation in each town will be a function of the PV systems installed, for which two scenarios have been generated.

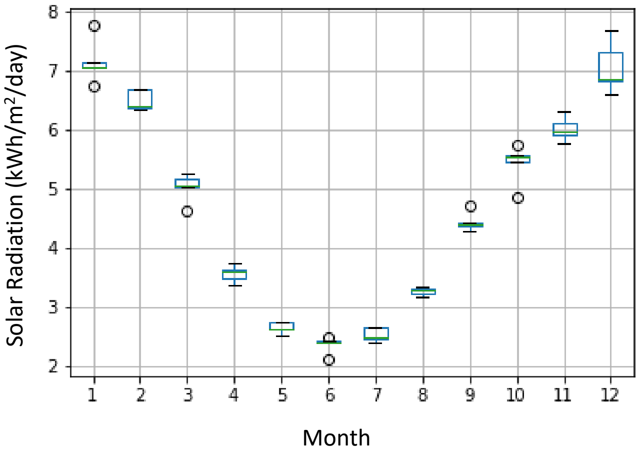


Figure 17. Box and whisker plot of the daily solar radiation (kWh/m^2/day) grouped per month using five years of historical data from the Bendigo weather station.

3.1.2.2 Extreme weather events

In addition to the solar radiation, that will affect the normal operation of the microgrid, the microgrid integrated investment and operation model can incorporate the economic impact of extreme weather events (e.g., bushfires, floods). The economic impact of these events is calculated as a function of the expected energy not served (MWh/year) and the VCR, which was provided by Powercor and is equal to $27.45/kWh.

The expected energy not served is an input for the model, and acquired from the parametric study carried out in Project 7, where different combinations of microgrid DER sizes (i.e., PV, diesel generator and battery storage) resulted in different expected energy not served (EENS) when the towns are not connected to the upstream grid (the assumption is that the microgrids in both Donald and Tarnagulla would not be connected to the upstream grid due to the extreme weather event). The microgrid integrated investment and operation model includes the EENS for a bushfire that does not cause fuel disruption (i.e., according to the assumptions made by Project 7, the bushfire with the highest probability of occurrence). The detailed results of the impact of microgrid DER sizes in the EENS can be found in the Project 7 report. It is assumed that a probability of one when including the expected costs from energy not served due to bushfires represents that every year during the lifetime of the microgrid there is a bushfire.

In the base case inclusion of extreme weather events it is assumed that two bushfires take place during the economic assessment horizon which would represent (2 bushfires/12 years) a probability equal to 0.167.

3.1.3 Market prices scenarios and assumptions

Wholesale market and contingency FCAS prices are two key value streams the microgrid can access. Nevertheless, the evolution of these system-level markets is uncertain and requires the use of scenarios, to understand their impact on investment decisions and resulting cash flows.

3.1.3.1 Wholesale Market Price Scenarios

As advised by Powercor, wholesale market price forecasts from the Australia Energy Outlook (AEO) developed by RepuTex were selected as the main input for future market scenarios [13]. This forecast provides annual average wholesale market prices for Victoria from 2022 to 2042 for three scenarios, which are presented in Figure 18. However, two challenges were encountered when using this forecast as an input for the investment and operational microgrid models. First, annual average prices do not have enough time granularity to display market volatility within a year, while also overlooking high prices periods where the microgrid might accrue most of its yearly revenues. Second, the different scenarios in Figure 18 are similar both in terms of annual average as well as price evolution during the economic assessment horizon.

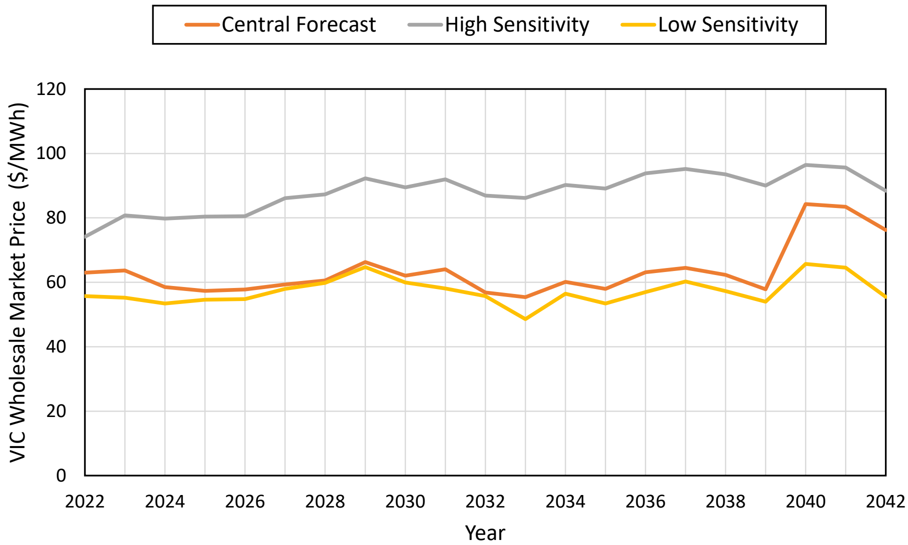


Figure 18. RepuTex yearly average wholesale market price forecast for Victoria from 2022 to 2042 comprised of three scenarios: Central Forecast and High and Low Sensitivity forecasts.

The first challenge was addressed first by extracting publicly available historical wholesale market data from 2010 to 2021, which presents adequate granularity to study the microgrid investment and operation problems (i.e., 30-minute granularity). Then, the wholesale market prices with 30-minute granularity of each year were divided by the annual average price to obtain “normalized” profiles for each year. Finally, these profiles can be scaled using the annual average price forecasted by RepuTex, and forecasted wholesale market prices with adequate granularity can be obtained. More detail on the methodology to generate 30-minute profiles for the microgrid investment and operational model can be found in Section 3.2

The second challenge required to create a new scenario of wholesale market prices, with significant differences from the RepuTex scenarios. This new scenario is not generated based on a methodology that estimates the state of the NEM in the next decade and the resulting prices. This scenario is motivated by the purpose of this project and aims to display the impact of a wholesale market with high and volatile prices in the microgrid investment and operation. However, historical data from 2011 to 2021 is used as a reference in terms of annual average prices and year-to-year changes in the annual average prices.

Figure 19 presents the two wholesale market price scenarios selected for the study of the microgrid investment and operation:

- Central Scenario (RepuTex): using the annual average wholesale market prices in Victoria as presented by RepuTex central scenario in the AEO and average volatility in price profiles based on historical data.
- High and Volatile Price Scenario: based on historical data, high annual average prices and high volatility in price profiles.

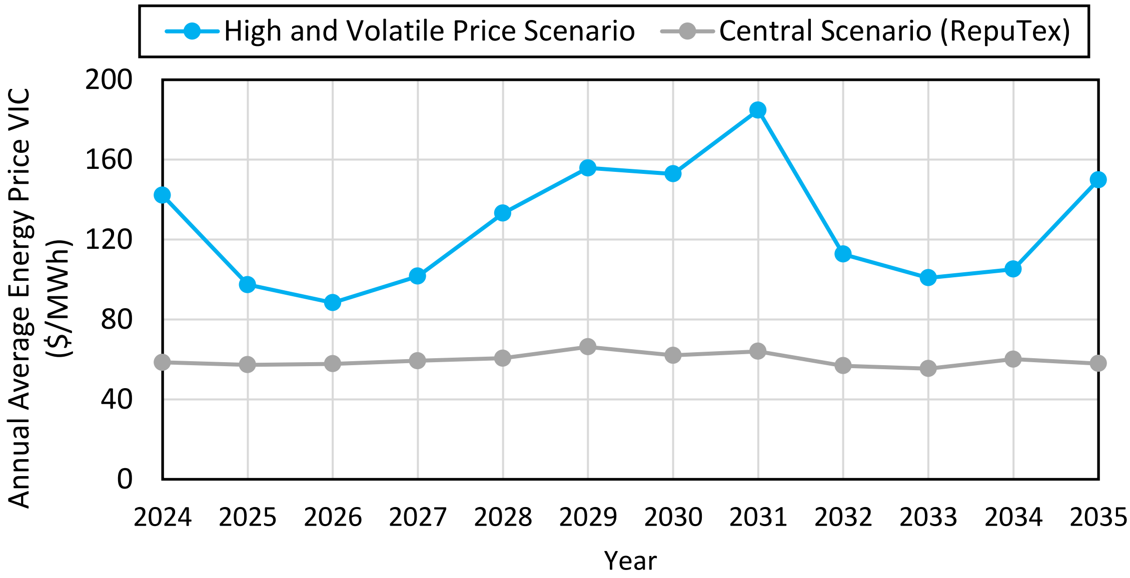


Figure 19. Annual average wholesale market price for the Central Scenario prepared by RepuTex and the high and volatile price scenario generated for the study of the microgrid investment and operation.

3.1.3.2 Contingency FCAS Price Scenarios

Contingency FCAS price forecasts were not provided. Therefore, historical market data is used to create two contingency FCAS price scenarios:

- “Low FCAS Price” scenario is generated by replicating the contingency FCAS prices from 2010 to 2015 with 30-minute granularity. The price profiles for these five years are replicated so as to fill in the whole project lifetime (12 years);
- “High FCAS” scenario is generated by replicating the contingency FCAS prices from 2016 to 2021 with 30-minute granularity. The price profiles for these five years are replicated so as to fill in the whole project lifetime (12 years).

These highly differentiated FCAS scenarios are designed to display the impact of relevant differences in FCAS prices in the microgrid investment and operation. The annual average of the six contingency FCAS markets for Low and High Price FCAS scenarios are presented in Figure 20. It must be noted that the six different FCAS contingency markets are considered for the analysis. Figure 20 presents the annual average price among markets to display the differences between the two FCAS prices scenarios while ensuring readability of the figure.

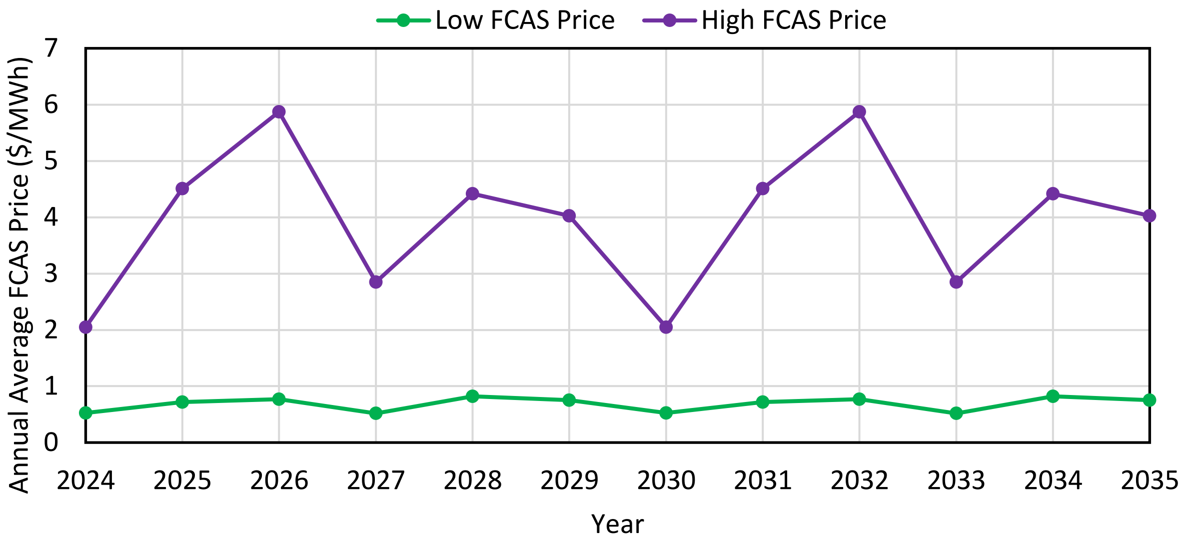


Figure 20. Annual price average in the six contingency FCAS markets for “High FCAS” and “Low FCAS” price scenarios for the horizon of the economic assessment, from 2024 to 2035.

3.2 Design Days and Months

When studying the investment and operation of a microgrid, an adequate time granularity must be selected. As discussed in the introduction to this chapter, 30-minute granularity is selected. However, it is computationally expensive to study the microgrid operation during its lifetime with this granularity. In addition to this, the microgrid investment and operation models have different attributes which affect the inputs required.

The microgrid integrated investment and operation model requires to assess all relevant input data within a single optimization problem to make the optimal investment decision. Once the optimal investment decision is fixed, the operation of the microgrid can be studied with more detail with the microgrid operational model, which can be easily divided in interdependent subproblems to guarantee computational efficiency. Therefore, for the microgrid integrated investment and operation model, design days are used to represent different years during the horizon of the economic assessment, whereas in the microgrid operational model, design months are used to represent different years. By using design months rather than days, more variability is included when assessing the microgrid operation, which in turn allows to evaluate more realistically the value that the microgrid brings to both communities.

3.2.1 Design Days

In the investment problem, each year in each future scenario will be represented by design days, that occur with a given frequency based on historical wholesale market data published by AEMO and smart meter data from Donald and Tarnagulla analysed in Project 7. The relevant design days, as well as the frequency in which they take place each year is presented in Table 2.

In the microgrid integrated investment and operation model each year is represented by the six days detailed in Table 2. Additionally, it is assumed that the operation of two consecutive years (e.g., Year 1 and Year 2) is the same, as to guarantee the investment optimization problem can be solved with a single optimization problem and problem decomposition is not necessary.

Table 2. Design days for the microgrid integrated investment and operation model

Design Day ID	System-level Markets	Local Generation	Local Demand	Frequency each year (365 days)
Summer	30-min price profile in summer	Median 30-min PV generation profile in summer	Median 30-min demand profile in summer	87
Autumn	30-min price profile in autumn	Median 30-min PV generation profile in autumn	Median 30-min demand profile in autumn	87
Winter	30-min price profile in winter	Median 30-min PV generation profile in winter	Median 30-min demand profile in winter	87
Spring	30-min price profile in spring	Median 30-min PV generation profile in spring	Median 30-min demand profile in spring	88
Volatile 1	High volatility 30-min price profile	30-min PV generation profile with minimum annual generation	30-min demand profile with maximum annual demand	8
Volatile 2	High volatility 30-min price profile	30-min PV generation profile with maximum annual generation	30-min demand profile with minimum annual demand	8

3.2.1.1 Generation of wholesale market price design days

To create 30-min wholesale market price profiles from the annual average values of each scenario the methodologies presented in Figure 21 and Figure 22 were performed, for the Central Scenario and the High and Volatile Scenario, respectively. The methodology performed to obtain design days for the wholesale market prices is presented as it is the most general and challenging generation of design days. This is because as profiles need to be created from historical market data, normalized, and then scaled using the forecasted annual average wholesale market price. The design days are generated based on quartile distribution.

- For the seasonal design days in the Central Scenario, the half-hourly median price (quartile 50%) considering all days of the season within a year is calculated.
- To generate the seasonal design days for the High and Volatile price scenario, for each season of each year of historical market data the daily volatility is calculated using the standard deviation. The seasonal design days are selected to be equal to the day of the season with the top 10% volatility (e.g., quartile 90%).
- High volatility days are calculated in the same way for the Central and High and Volatile scenario, choosing for each year the day with a volatility equal to the top 2% (quartile 98%).

The resulting normalized profiles from historical data for the Central scenario in spring, summer, autumn and winter are presented in Figure 23, Figure 24, Figure 25, and Figure 26, respectively. The resulting normalized profiles from historical data for the High and Volatile scenario in spring, summer, autumn and winter are presented in Figure 27, Figure 28, Figure 29 and Figure 30 respectively. The high volatility design days are the same for both scenarios and presented in Figure 31. These design days are then assigned to the different years for the analysis of the microgrid (2024 to 2035) and multiplied by the corresponding annual average wholesale market price of each scenario. As mentioned in Section 3.1, the objective is not to create accurate profiles, but to model the different value the microgrid can provide in significantly different conditions, in this case comparing significantly different price volatility in the wholesale market.

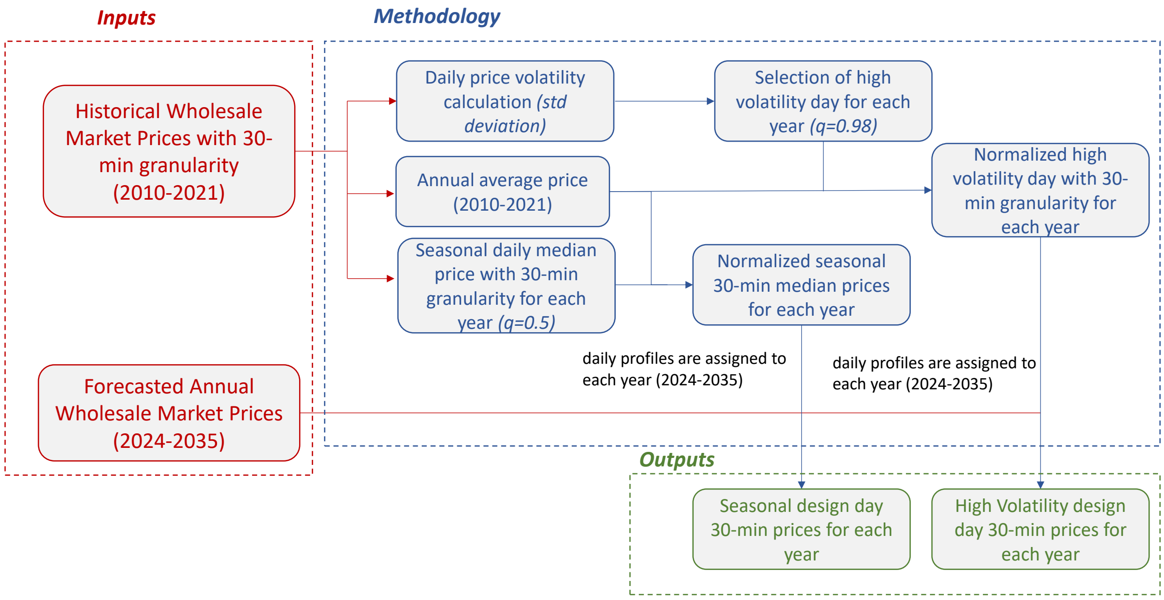


Figure 21. Methodology to generate wholesale market price profiles with 30-minute granularity to produce design days for the Central Wholesale market price scenario

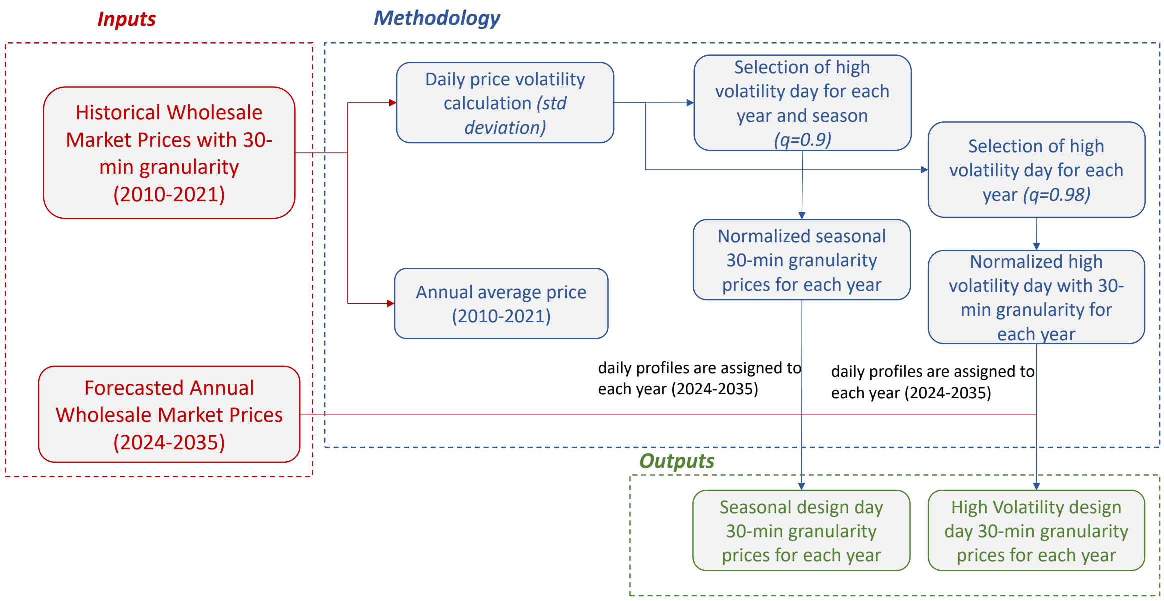


Figure 22. Methodology to generate wholesale market price profiles with 30-minute granularity to produce design days for the High and Volatile Wholesale market price scenario

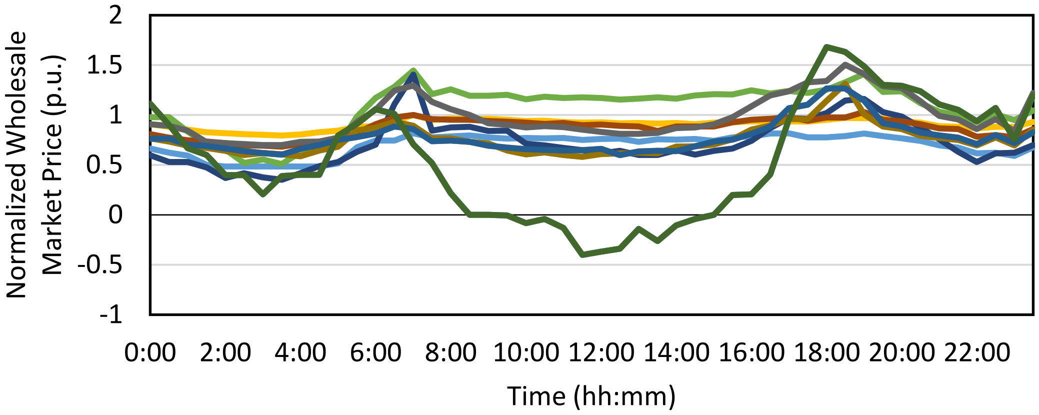


Figure 23. Normalized wholesale market prices for the spring design day in the Central Scenario with 30-min granularity based on historical market data.

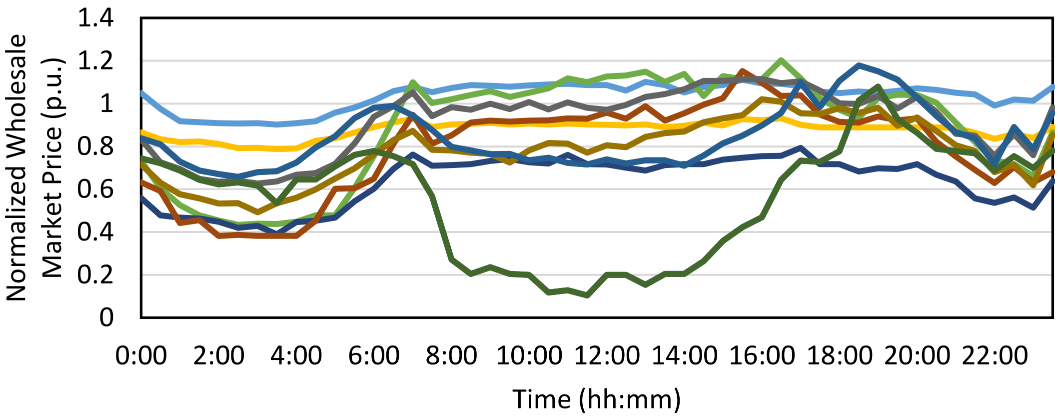


Figure 24. Normalized wholesale market prices for the summer design day in the Central Scenario with 30-min granularity based on historical market data.

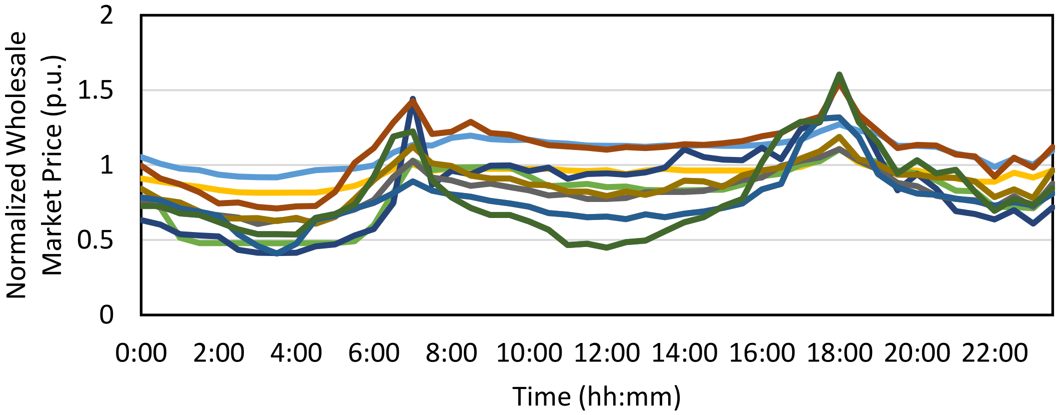


Figure 25. Normalized wholesale market prices for the autumn design day in the Central Scenario with 30-min granularity based on historical market data.

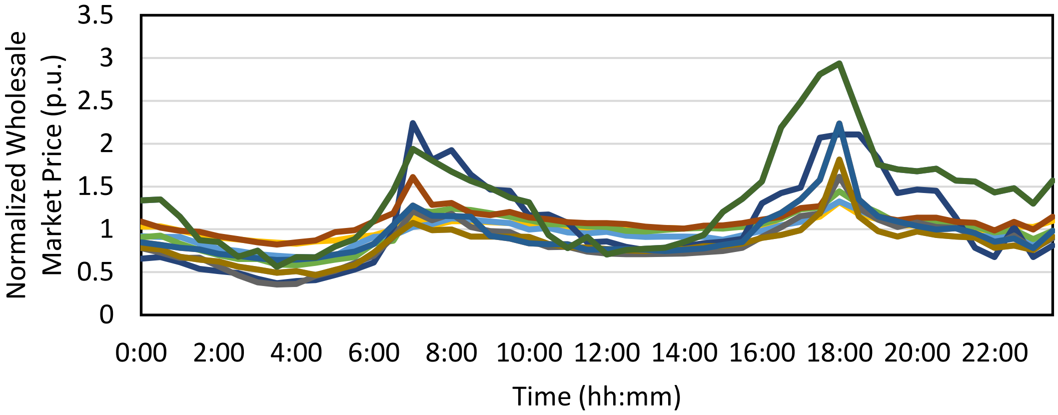


Figure 26. Normalized wholesale market prices for the winter design day in the Central Scenario with 30-min granularity based on historical market data.

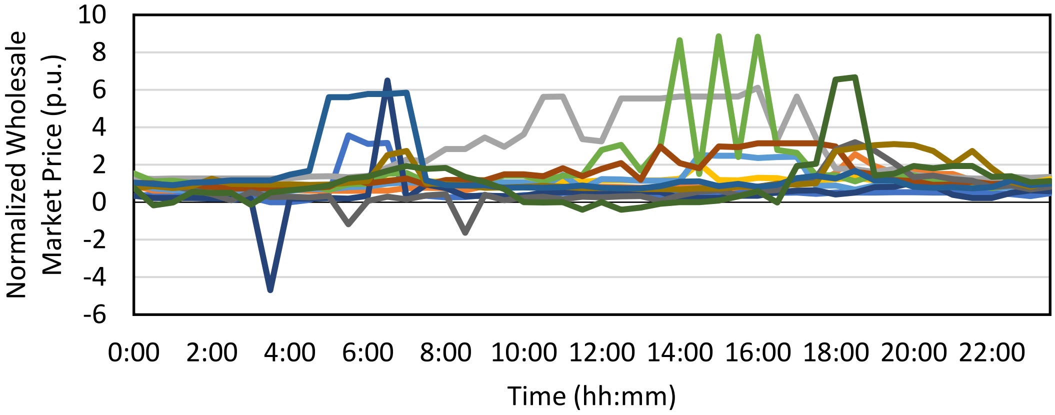


Figure 27. Normalized wholesale market prices for the spring design day in the High and Volatile Scenario with 30-min granularity based on historical market data.

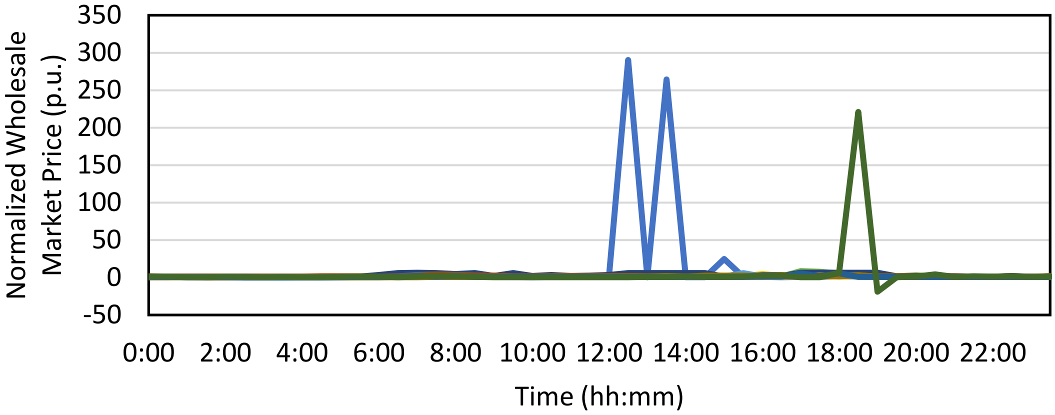


Figure 28. Normalized wholesale market prices for the summer design day in the High and Volatile Scenario with 30-min granularity based on historical market data.

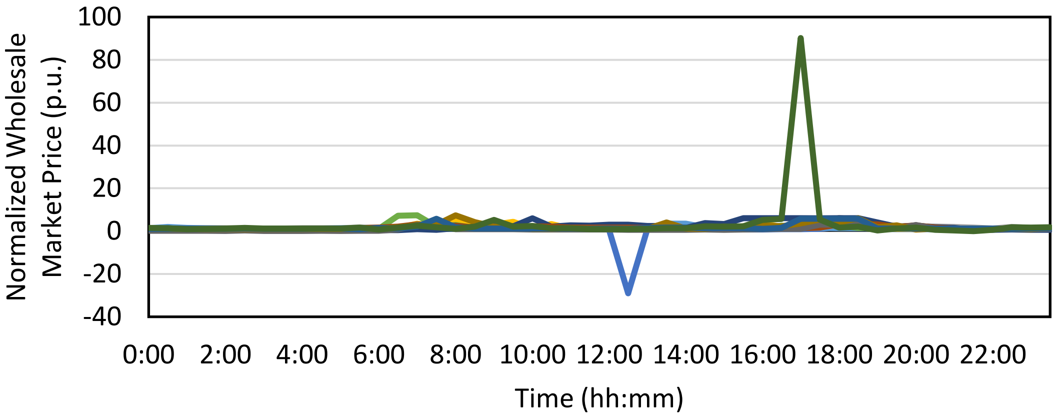


Figure 29. Normalized wholesale market prices for the autumn design day in the High and Volatile Scenario with 30-min granularity based on historical market data.

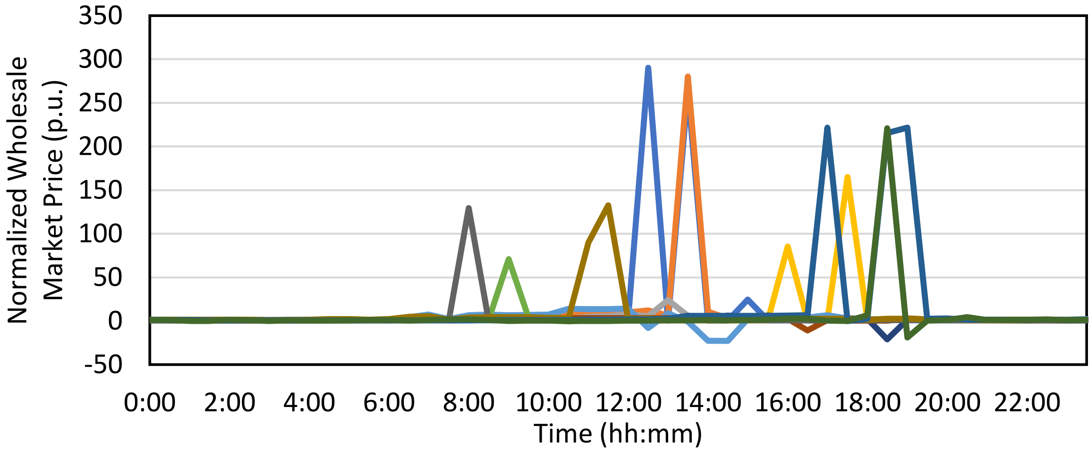


Figure 30. Normalized wholesale market prices for the winter design day in the High and Volatile Scenario with 30-min granularity based on historical market data.

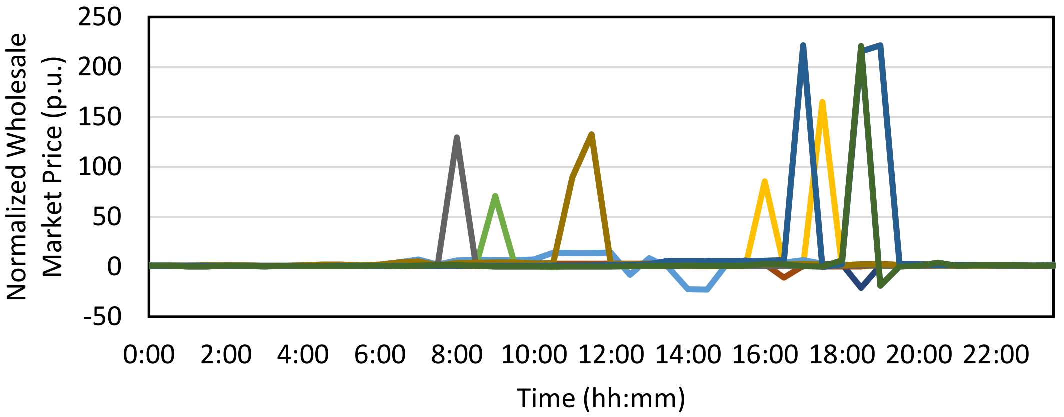


Figure 31. Normalized wholesale market prices for the high volatility design day with 30-min granularity based on historical market data.

3.2.1.2 Generation of contingency FCAS price design days

In the case of FCAS, the same process as the one detailed in Figure 21 is carried out to generate seasonal design days of FCAS prices and high volatility FCAS price design days, for each of the six contingency FCAS market prices. However, since no forecasts on future FCAS prices are provided, and the FCAS price scenarios are based on historical data, there is no need to normalize FCAS prices. For the Low FCAS Price scenario the seasonal and high volatility design days from 2010 to 2015 are obtained and replicated so as to fill in the whole project lifetime (12 years). For the High FCAS price scenario the seasonal and high volatility design days from 2016 to 2021 are obtained and replicated so as to fill in the whole project lifetime (12 years). Figure 32 presents an example of the six design days generated using historical market data from the year 2010, which will be used in the Low FCAS scenario. Figure 33 presents an example of the six design days generated using historical market data from the year 2017, which will be used in the High FCAS scenario. It must be noted that the model includes the six contingency FCAS markets, but average prices among markets are presented to guarantee the readability of the figure. The significant differences perceived in the FCAS prices when comparing Figure 32 and Figure 33 are equivalent to the differences of the remaining years assigned to each scenario, which are not presented in the report.

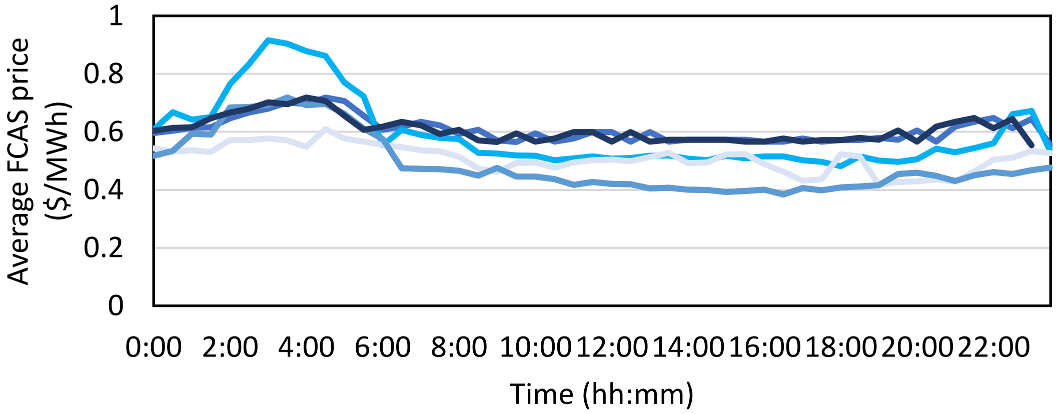


Figure 32. Average price among the six contingency FCAS markets showing the six design days that represent 2010 historical market data.

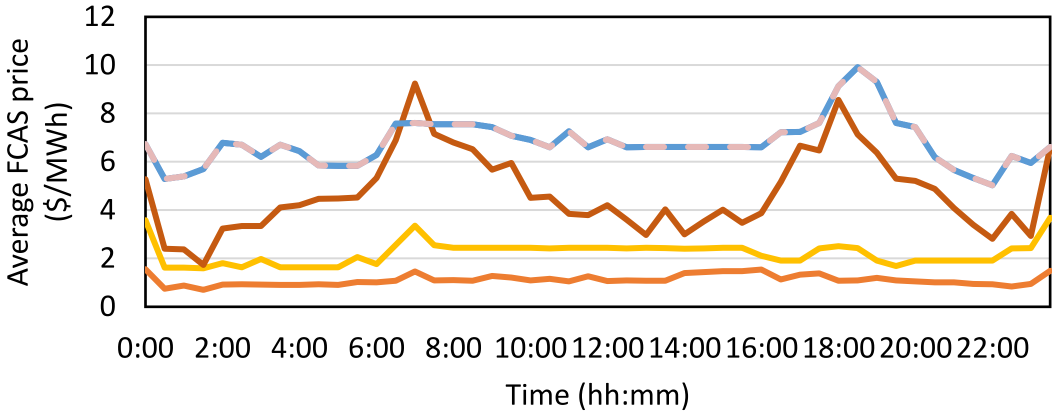


Figure 33. Average price among the six contingency FCAS markets showing the six design days that represent 2017 historical market data.

3.2.1.3 Generation of local PV and demand conditions design days

In the case of local system conditions (customer demand and PV generation) the same methodology as the presented in Figure 21 was performed. In this case, like in FCAS there is no need to normalize profiles and the seasonal design days as well as the maximum demand/minimum generation and minimum demand/maximum generation are retrieved directly from the smart meter data provided by Project 7. These design days remain constant for the different years within the microgrid investment and operational problems. However, depending on the scenarios presented in Section 3.1.1, the corresponding demand factor of growth is applied to the demand in all the design days of each year. In addition, the number of PV systems in place will affect the available PV generation. However, the same profile of solar radiation in each design day is assumed constant through the years. Figure 34 represents the different design days for the town of Tarnagulla, while Figure 35 represents the different design days for the town of Donald directly coming from the smart meter data from Project 7 (e.g., not applying load growth factors or including new PV systems).

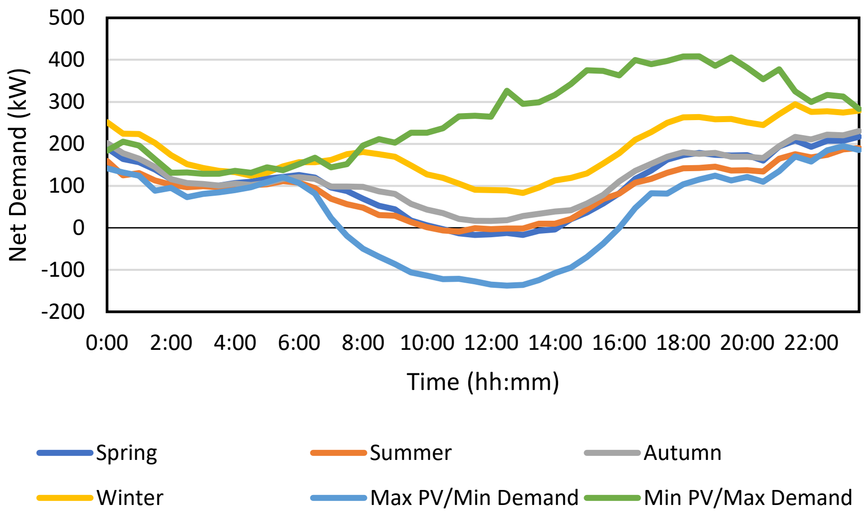


Figure 34. Six design days of the aggregated net demand in Tarnagulla generated using smart meter data from Project 7

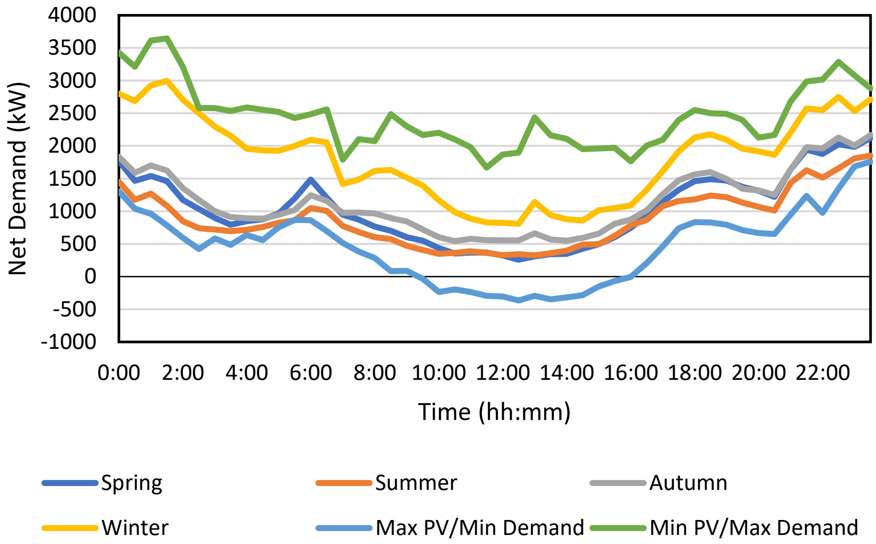


Figure 35. Six design days of the aggregated net demand in Donald generated using smart meter data from Project 7

3.2.2 Design Months

As discussed in previous sections, the operational model provides further flexibility and can be divided into inter-dependent subproblems, which allows to efficiently model the microgrid operation in more detail than the investment problem. Therefore, rather than using design days, each year is represented by four design months, corresponding to each season as shown in Table 3. This allows to better display the variability within a year of operation of the microgrid, as a month will include days with higher price volatility, days with higher and lower prices, negative prices etc. Like in the investment problem, it is assumed that the operation of two consecutive years (Year 1 and Year 2) is the same.

Table 3. Design months for the microgrid operational model

Design Day ID	System-level Markets	Local Generation	Local Demand	Frequency each year (12 months)
Summer	30-min price profile in a summer month	30-min PV generation profile in a summer month	30-min demand profile in a summer month	3
Autumn	30-min price profile in an autumn month	30-min PV generation profile in an autumn month	30-min demand profile in an autumn month	3
Winter	30-min price profile in a winter month	30-min PV generation profile in a winter month	30-min demand profile in a winter month	3
Spring	30-min price profile in a spring month	30-min PV generation profile in a spring month	30-min demand profile in a spring month	3

3.2.2.1 Generation of wholesale market price design days

The same philosophy behind the methodologies presented in Figure 21 and Figure 22 is applied to generate "design months". The details of the methodology to generate design months for both wholesale market price scenarios are presented in Figure 36. In this case, data analysis is carried out to find the month in each season that presented the highest volatility, as well as median volatility (quartile 50%). The month with highest volatility is assigned to the High and Volatile scenario, whereas the month with median volatility is assigned to the Central Scenario. This is repeated for each season, so each year is represented by four design months. As opposed to the generation of design days for the microgrid integrated investment and operation model, there are no "volatile design months". This is due to the fact that just by including a larger set of days to represent a year in the microgrid operational problem (4 months, one per season, each comprised of 30 days) high volatility days will be captured.

It is important to note that while the design days in the investment model differ from the design months in the operational model, both are generated using the same dataset, with design months just being a "less processed" version of design days. The normalized spring, summer, autumn and winter design months from historical market data for the Central Scenario are presented in Figure 37, Figure 38, Figure 39, and Figure 40, respectively. The resulting normalized profiles from historical data for the High and Volatile scenario in spring, summer, autumn and winter are presented in Figure 41, Figure 42, Figure 43 and Figure 44respectively. These design months are then assigned to the different years for the analysis of the microgrid (2024 to 2035) and multiplied by the corresponding annual average wholesale market price of each scenario. As mentioned in Section 3.1, the objective is not to create accurate profiles, but to model the different value the microgrid can provide in significantly different conditions, in this case comparing significantly different price volatility in the wholesale market.

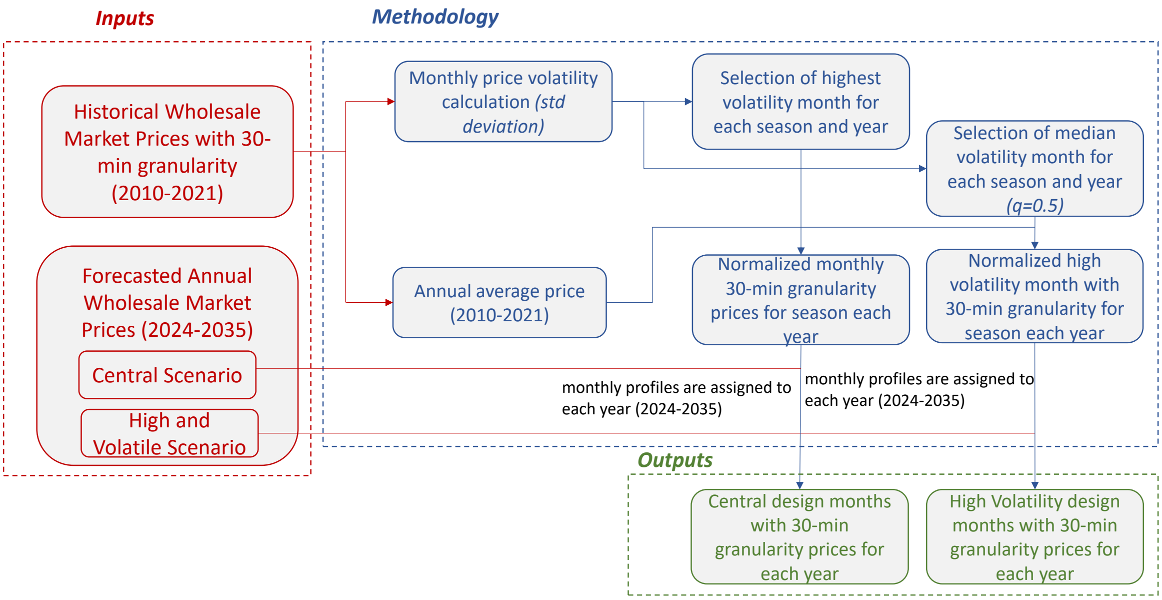


Figure 36. Methodology to generate wholesale market price profiles with 30-minute granularity to produce design months for the Central and High and Volatile wholesale market price scenarios

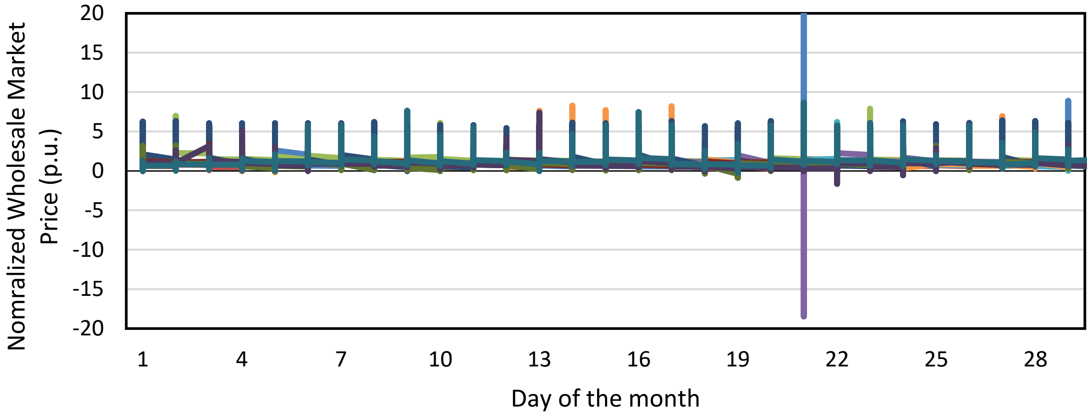


Figure 37. Normalized wholesale market prices for the spring design month in the Central Scenario with 30-min granularity based on historical market data.

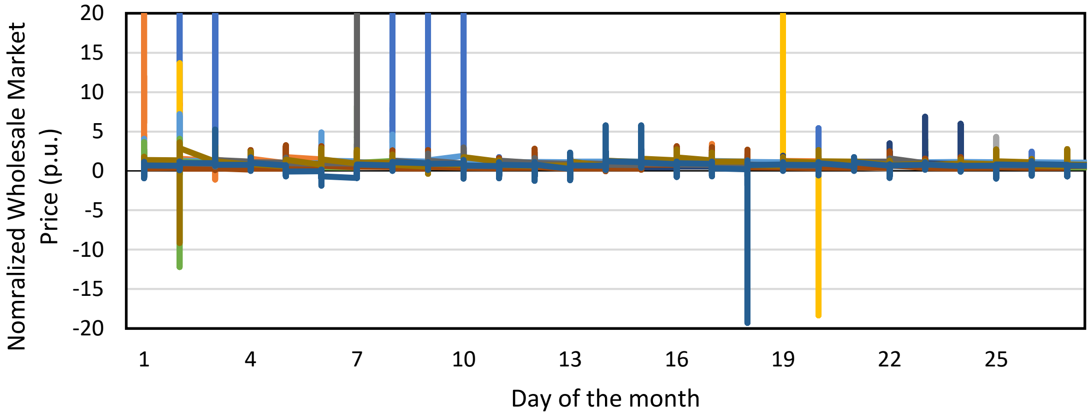


Figure 38. Normalized wholesale market prices for the summer design month in the Central Scenario with 30-min granularity based on historical market data.

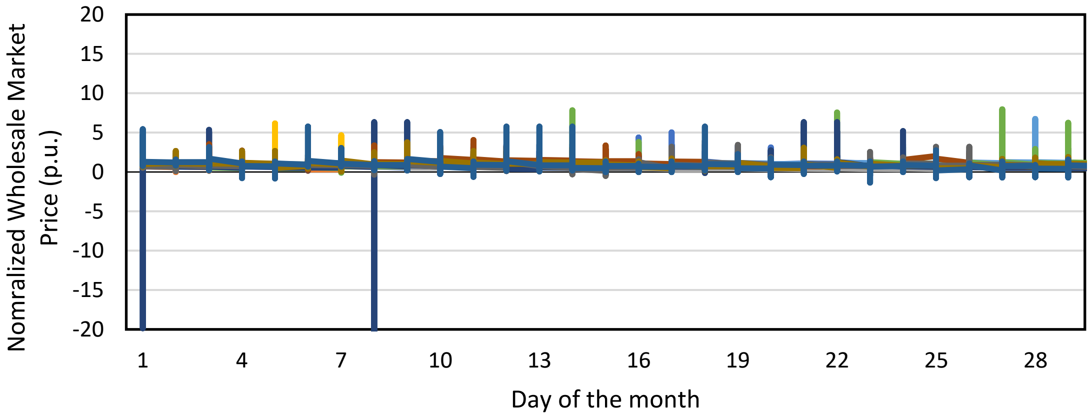


Figure 39. Normalized wholesale market prices for the fall design month in the Central Scenario with 30-min granularity based on historical market data.

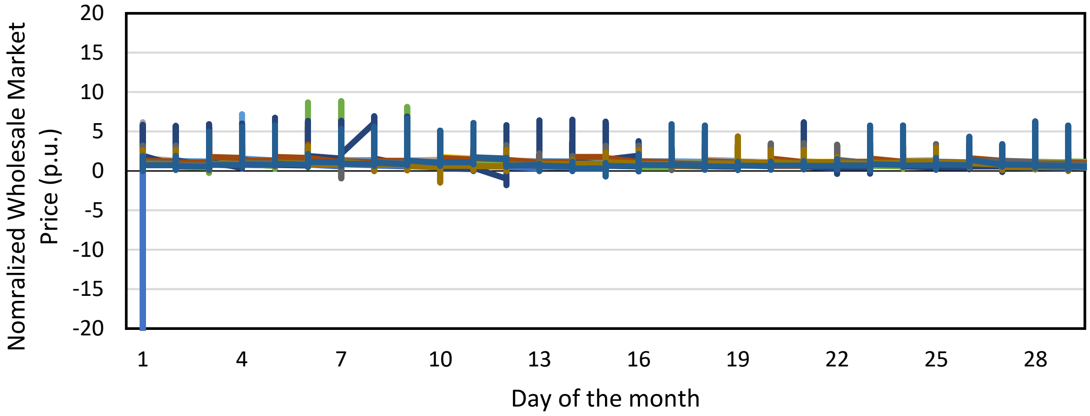


Figure 40. Normalized wholesale market prices for the winter design month in the Central Scenario with 30-min granularity based on historical market data.

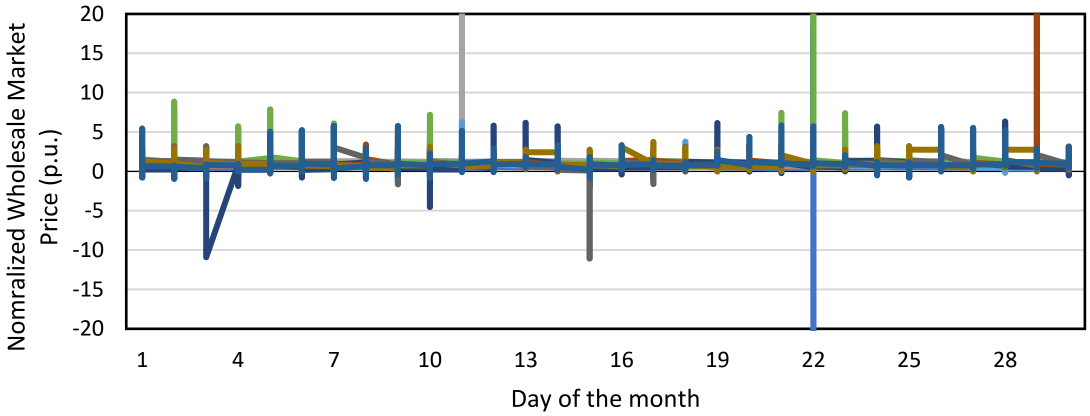


Figure 41. Normalized wholesale market prices for the spring design month in the High and Volatile Scenario with 30-min granularity based on historical market data.

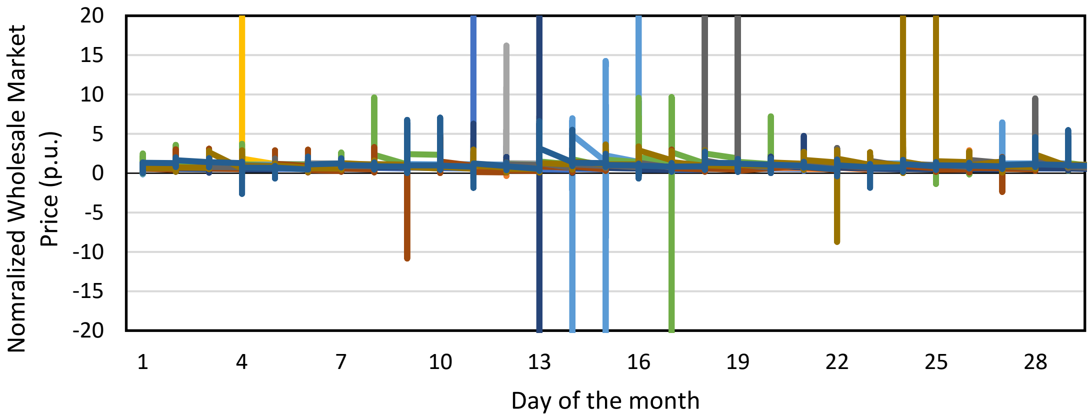


Figure 42. Normalized wholesale market prices for the summer design month in the High and Volatile Scenario with 30-min granularity based on historical market data.

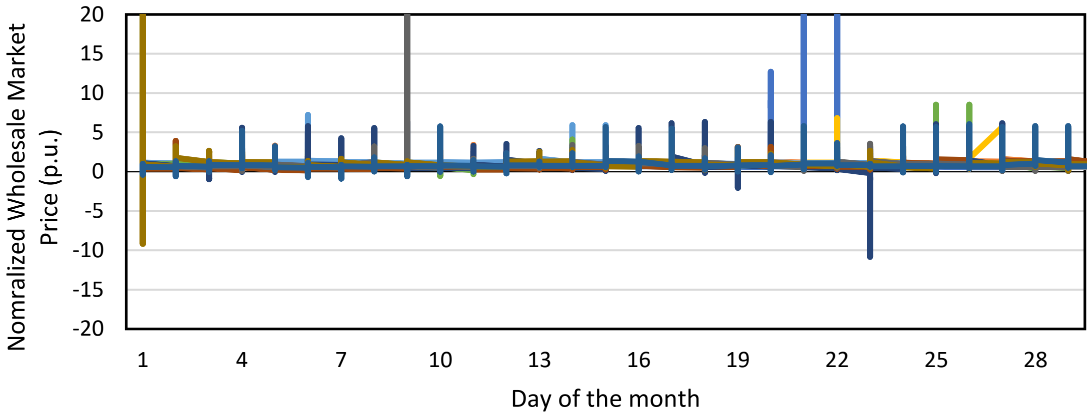


Figure 43. Normalized wholesale market prices for the fall design month in the High and Volatile Scenario with 30-min granularity based on historical market data.

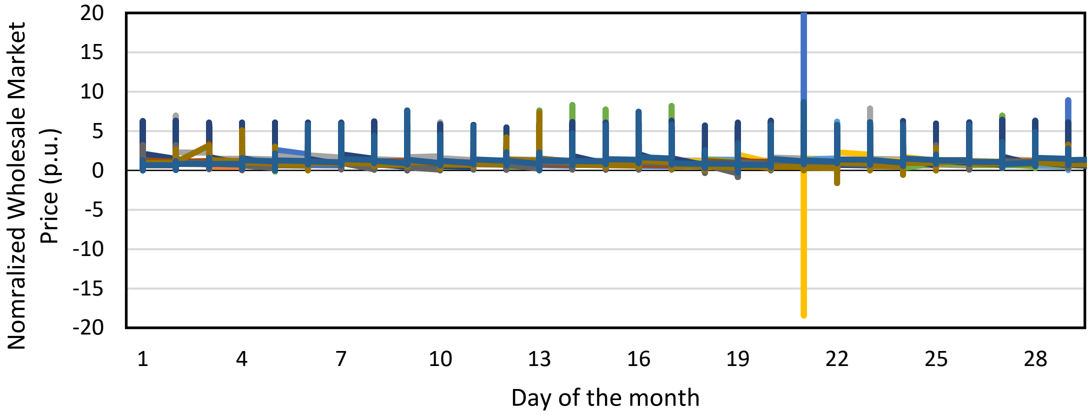


Figure 44. Normalized wholesale market prices for the winter design month in the High and Volatile Scenario with 30-min granularity based on historical market data.

3.2.2.2 Generation of contingency FCAS price design months

In the case of FCAS, a similar process as the one detailed in Figure 36 for the Central Scenario of wholesale market prices is carried out to generate design months. Since no forecasts on future FCAS prices are provided, and the FCAS price scenarios are based on historical data, there is no need to normalize FCAS prices. The design months for each season and year are selected to have the median volatility. For the Low FCAS Price scenario the design months are selected for each season and each year from 2010 to 2015. These five years of data are replicated so as to fill in the whole project lifetime (12 years). For the High FCAS Price scenario the design months are selected for each season and each year from 2016 to 2021. These six years of data are replicated so as to fill in the whole project lifetime (12 years).

3.2.2.3 Generation of local PV and demand conditions design months

In the case of local system conditions (customer demand and PV generation) the same methodology as the presented in Figure 36 for the Central Scenario of wholesale market prices is carried out to generate design months. In this case, like in FCAS there is no need to normalize profiles and the design months are retrieved directly from the smart meter data provided by Project 7. These design months remain constant for the different years within the microgrid investment and operational problems. However, depending on the scenarios presented in Section 3.1.1, the corresponding demand factor of growth is applied to the demand in all the design months of each year. In addition, the number of PV systems in place will affect the available PV generation. However, the same profile of solar radiation in each design month is assumed constant through the years.

3.3 Community Data

An input for both the microgrid integrated investment and operation model and operational model is the MV network and customer demand and generation aggregated at MV/LV transformer level. Considering the MV network in both the microgrid investment and operational model is relevant as it will inform on the best location of the microgrid DER as well accurately representing the local constraints that impact the value the microgrid DER can provide.

The MV network data (MV/LV transformer and line characteristics such as thermal limits, ampacity limits, resistance and reactance, and network topology) comes from the DIgSILENT model developed in Project 5. The demand and customer-owned PV currently present in each town aggregated at the MV/LV transformer level is acquired from the data analysis performed in Project 7. Customer reactive power consumption was not provided by Project 7. Therefore, customer reactive power consumption, aggregated at MV/LV transformer level is calculated using customer demand, assuming an aggregated power factor equal to 0.98.

3.3.1 Tarnagulla

The MV network of Tarnagulla has a voltage level of 22kV and its topology is displayed in Figure 45. Voltages in the MV network are bounded to remain in the interval of ±5% of the nominal voltage.

The following table presents the current local demand and generation conditions, as well as the battery storage capacity installed in Tarnagulla. The data presented is retrieved from the smart meter data analysis performed in Project 7

Table 4. Tarnagulla demand, PV generation and battery storage capacity installed

Annual Energy Consumption (GWh)	Peak Demand (MW)	Annual PV Generation (GWh)	Peak PV Generation (MW)	Battery Storage Installed (MWh)
1.3	0.41	0.26	0.19	0

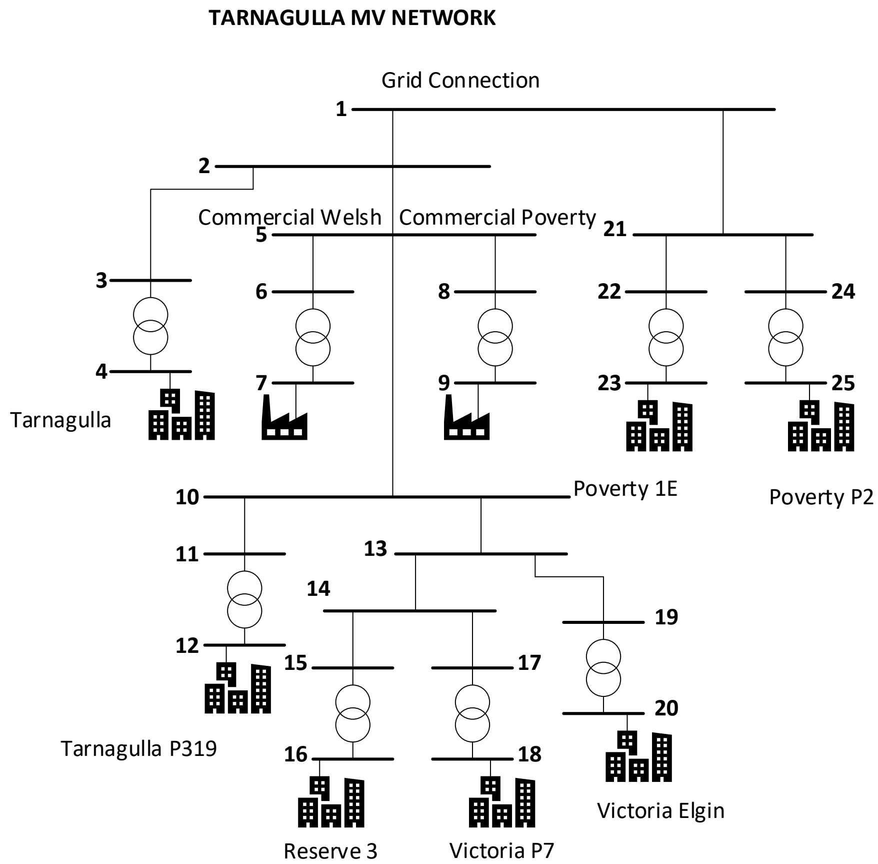


Figure 45. Tarnagulla MV network included in the microgrid investment and operational model

3.3.2 Donald

The MV network of DONALD has a voltage level of 22kV and its topology is displayed in Figure 46. Voltages in the MV network are bounded to remain in the interval of ±5% of the nominal voltage.

The following table presents the current local demand and generation conditions, as well as the battery storage capacity installed in Donald. The data presented is retrieved from the smart meter data analysis performed in Project 7

Table 5. Donald demand, PV generation and battery storage capacity installed

Annual Energy Consumption (GWh)	Peak Demand (MW)	Annual PV Generation (GWh)	Peak PV Generation (MW)	Battery Storage Installed (MWh)
12.45	3.67	1.28	0.86	0

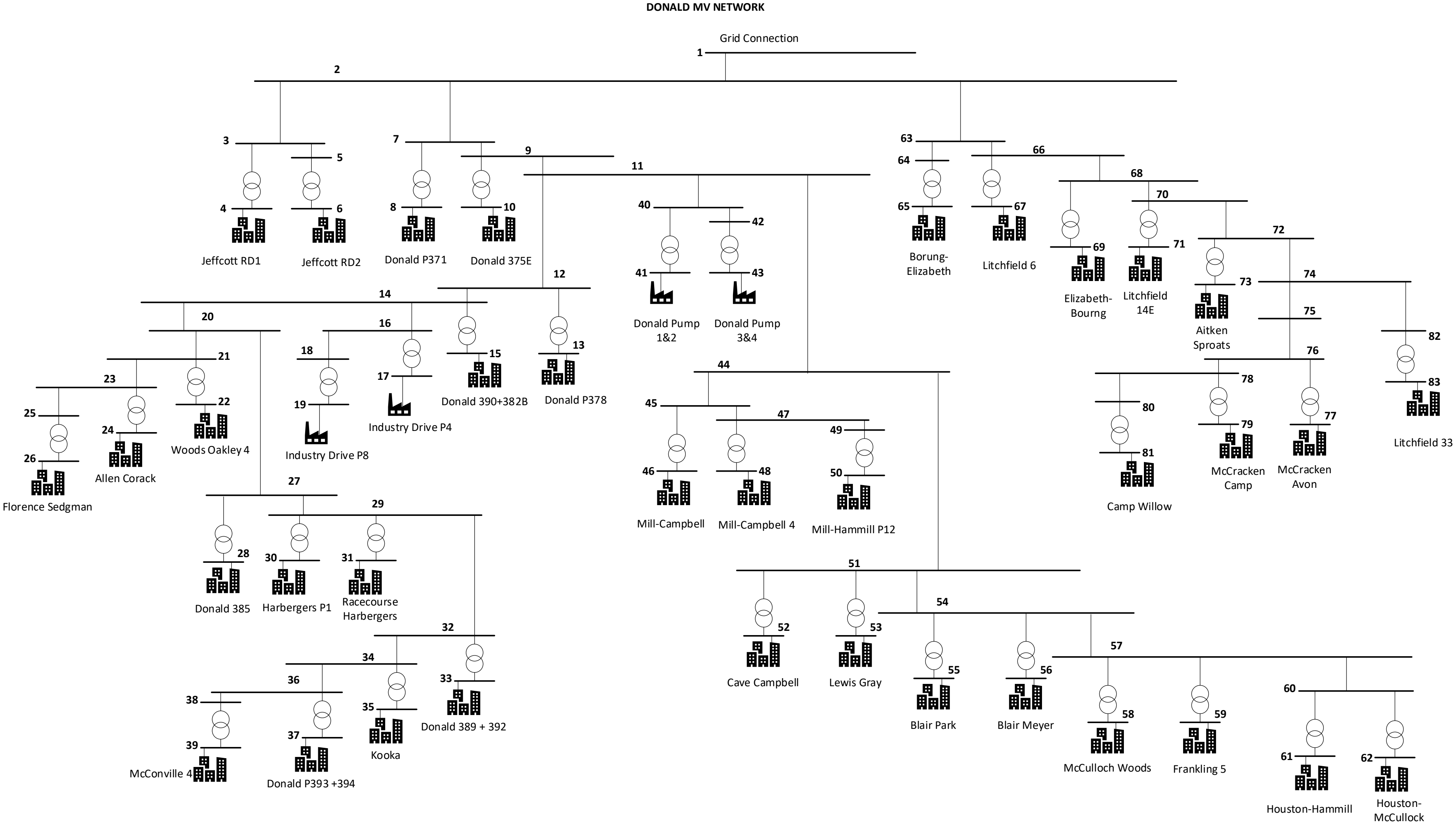


Figure 46. Donald MV network included in the microgrid investment and operational model

3.4 Microgrid Techno-economic Data

This section presents the remaining techno-economic inputs required for the techno-economic framework.

3.4.1 DER Techno-economic Data

Table 6 presents the main economic parameters of the microgrid DER introduced in the techno-economic framework. CAPEX, OPEX and DER lifetime are only included in the microgrid investment problem, whereas the marginal cost of the DER is included in both the microgrid integrated investment and operation model and the microgrid operational model. CAPEX and OPEX are estimated following previous projects of microgrids in Victoria and publicly available data from AEMO [14], [15] as advised by project partners, such as Powercor. As mentioned in Chapter 1, fixed costs are not included in the investment model to avoid the use of binary variables. Nevertheless, in the CAPEX and OPEX presented in Table 6 these fixed costs are included after the microgrid integrated investment and operation model is run and a proxy of DER sizes in both microgrid is known. Marginal cost for PV and battery systems is equal to 1 to ensure that the operation of the resources is constrained in the optimisation problem that defines the microgrid investment and operation. In the diesel generator the marginal cost corresponds to the fuel cost, following the estimation presented in [14]. Finally, the lifetime of each asset is obtained from [14] and are considered to calculate the project lifetime and the salvage value of the PV and diesel generator at the end of the project.

Table 6. Microgrid DER Economic data

DER	CAPEX ($/MW)	CAPEX ($/MWh)	OPEX ($/MW year)	Marginal cost ($/MWh)	Lifetime (years)
PV	1000000	0	15490	1	25
Battery	648000	710000	25000	1	12
Diesel Generator	650000	0	4103	300	20

Table 7 presents the main technical parameters of the microgrid DER. The values presented are in per unit and are a function of the investment decision in the microgrid integrated investment and operation model. For instance, if the investment decision is to install 1 MW of PV generation, the values in Table 7 should be multiplied by 1 MW to obtain the different technical parameter of the DER. In the case of the battery a minimum generation of -1 p.u. is used to model the ability of the battery to discharge (exporting power with a positive sign) and charge (importing power with a negative sign). Reactive power capabilities of each DER are presented following the same sign convention were injecting power has a positive sign, whereas absorbing reactive power has a negative sign. The roundtrip efficiency of the battery is assumed to be equal to 85% as proposed by [14]. Finally, activation times and ramp rates, which are critical to participate in contingency FCAS markets come from technical literature [2], [16] The selected values result on PV and battery potentially being able to participate in all six contingency FCAS markets, whereas diesel generators have a response time that does not allow them to participate in any contingency FCAS market.

Table 7. Microgrid DER Technical data

DER	Max. Generation (p.u.)	Min. Generation (p.u.)	Reactive power injection/ absorption (p.u.)	Roundtrip Efficiency (-)	Activation time (s)	Ramp rate (p.u./s)
PV	1	0	1/-1	-	1	1
Battery	1	-1	1/-1	0.85	0.1	2
Diesel Generator	1	0	0.6/-0.4	-	360	0.005

3.4.2 Microgrid Project Data

The following data is used for the microgrid project:

- Horizon of the economic assessment: 12 years (equal to the lifetime of the battery)
- Discount rate: 5.4%

3.4.3 Other data

Motivated with the objective of including all costs and benefits that the different actors in the microgrid are subject to, NUoS are considered to be applied to customer imports at the MV/LV transformer level.

In practice NUoS are charged to each customer individually, according to the energy imports measured by their smart meter at their point of connection with the LV network. However, given that Project 8 is only modelling the MV network and only has access to data aggregated at MV/LV transformer level, NUoS are charged to the aggregate demand at each MV/LV transformer, providing an estimate of the network charges of customers.

In the microgrid investment and operational model fixed costs (cents/day) are not included, as the number of customers has only been estimated and these costs cannot be optimized within the microgrid operation (these are charged daily regardless of the customer imports or exports). All customers in both Donald and Tarnagulla are assumed to follow the Residential ToU tariff, and prices follow the indicative pricing schedule published by Powercor for 2025/2026 during the whole horizon of the economic assessment.

Table 8. NUoS for customer imports charged at MV/LV transformer level

Network Tariff	Fixed (cents/day)	Usage Peak (cents/kWh)	Usage off-Peak (cents/kWh)
Residential ToU	38.35	17.24	4.32

4 Techno-Economic Framework Results

4.1 Microgrid Investment Case Studies

An outcome of this project is to provide the cost-benefit trade-offs between the value that different DER options can provide. Given the uncertain future development in system-level markets and local conditions, it is paramount to understand the different investment decisions recommended for the different future scenarios presented in 3.1. To understand the impact of different uncertainties various case studies are defined for the two wholesale market price scenarios Central and High and Volatile in Table 9 and Table 10, respectively.

Table 9. Case studies for the investment problem in Tarnagulla using the central wholesale market price scenario

Case Study ID	Scenarios					
	Wholesale Market	**Contingency FCAS**	**Customer Demand**	**Customer DER**	**Inclusion of EENS**	**Inclusion of Carbon Cost**
Base	Central	Low FCAS	BAU	BAU	No	No
EENS	Central	Low FCAS	BAU	BAU	**Yes**	No
High FCAS	Central	**High FCAS**	BAU	BAU	No	No
High FCAS + EENS	Central	**High FCAS**	BAU	BAU	**Yes**	No
High demand	Central	Low FCAS	**High demand**	BAU	No	No
High demand + EENS	Central	Low FCAS	**High demand**	BAU	**Yes**	No
DER	Central	Low FCAS	BAU	**Increased DER**	No	No
DER + EENS	Central	Low FCAS	BAU	**Increased DER**	**Yes**	No

Table 10. Case studies for the investment problem in Tarnagulla using the High and Volatile wholesale market price scenario

Case Study ID	Scenarios					
	Wholesale Market	**Contingency FCAS**	**Customer Demand**	**Customer DER**	**Inclusion of EENS**	**Inclusion of Carbon Cost**
Base	High and Volatile	Low FCAS	BAU	BAU	No	No
EENS	High and Volatile	Low FCAS	BAU	BAU	**Yes**	No
High FCAS	High and Volatile	**High FCAS**	BAU	BAU	No	No
High FCAS + EENS	High and Volatile	**High FCAS**	BAU	BAU	**Yes**	No
High demand	High and Volatile	Low FCAS	**High demand**	BAU	No	No
High demand + EENS	High and Volatile	Low FCAS	**High demand**	BAU	**Yes**	No
DER	High and Volatile	Low FCAS	BAU	**Increased DER**	No	No
DER + EENS	High and Volatile	Low FCAS	BAU	**Increased DER**	**Yes**	No

4.1.1 Investment Results for a microgrid located in Tarnagulla

4.1.1.1 Deterministic investment analysis

The Tarnagulla investment decisions for the case studies defined by Table 9 and Table 10 are presented in Figure 47 and Figure 48, respectively.

It is important to note that EENS estimates as a function of different DER technology sizes comes from a parametric study performed in Project 7. The results for both Donald and Tarnagulla displayed that increasing PV investment size had the largest impact on reducing EENS. However, it must be noted that these parametric studies did not consider the MV network within the community. Therefore, possible MV network constraints that might result in PV curtailment are not captured. Considering also the existing customer-owned PV and the fact that all PV generation occurs at the same time this might result on an overestimate of the ability of PV to effectively reduce EENS. Other aspects not considered in Project 7 that might affect these results are not including the PV efficiency reduction due to ash and smoke of bushfires, and the PV efficiency reduction due to high temperatures, which also are likely to take place during bushfire events that occur during summer.

The results in Figure 47 represent the impact of different scenarios in the investment decisions in Tarnagulla under the assumptions behind the Central wholesale market price scenario (lower prices and limited price volatility). Importantly, the results display that in the case of Central wholesale market price scenario, investment in a PV system is not required. This is mainly due to wholesale market prices in this scenario are low, especially at times of high PV penetration, whereas price spikes do not occur at times of high PV generation, therefore the value additional PV can provide is limited during the microgrid normal operation. Additionally, given that there is customer-owned PV, MV network models can constraint at times of high PV exports further PV generation. It must be noted the results only display battery capacity installed, as in all scenarios the battery installed have a duration of approximately 1 hour.

The base case displays that in the current conditions of Tarnagulla, only investment in diesel generator is required. The diesel generator is used for arbitrage, to meet demand at time of high wholesale market prices (e.g., prices higher than $300/MWh, given the marginal cost of the diesel generator). However, when the impact of bushfires is included, the capacity installed of the diesel generator considerably increases to reduce the expected costs of EENS. The results display that high FCAS prices drive the investment in battery system, as this technology can accrue considerable FCAS revenues for the microgrid. When considering bushfires, the battery capacity installed remains the same, however investment in a diesel generator is recommended to reduce the costs of EENS, as according to Project 7 the diesel generator has a larger impact on reducing the EENS than the battery, while also providing the benefit of arbitrage when wholesale market prices are higher than $300/MWh.

In the scenarios of high demand and increased DER the results are similar, with larger batteries being installed in the microgrid and small diesel generators being required. However, the drivers of the investment decision are different. In high demand, the battery is used for arbitrage, charging at times where the wholesale market price is low, and discharging at times wholesale market is high to meet demand, with the support of the diesel generator for the price spikes. As the demand is higher overall, and spike prices in the Central scenario are limited, the battery with lower operational costs provides a better solution than a larger diesel generator. In the case of increased DER, the battery investment is used to charge the increased PV generation of customer-owned resources and discharge when the PV generation is not present, as well as providing wholesale market arbitrage. The diesel generator supports the operation of the microgrid by generating at times of price spikes. Interestingly, in these two cases where the DER investment is higher the impact of considering EENS is limited, with an incremental increase in both resources. This displays that there are some synergies in scenarios, where the investment required for normal operation would suffice to also reduce the impact of bushfires to optimal levels.

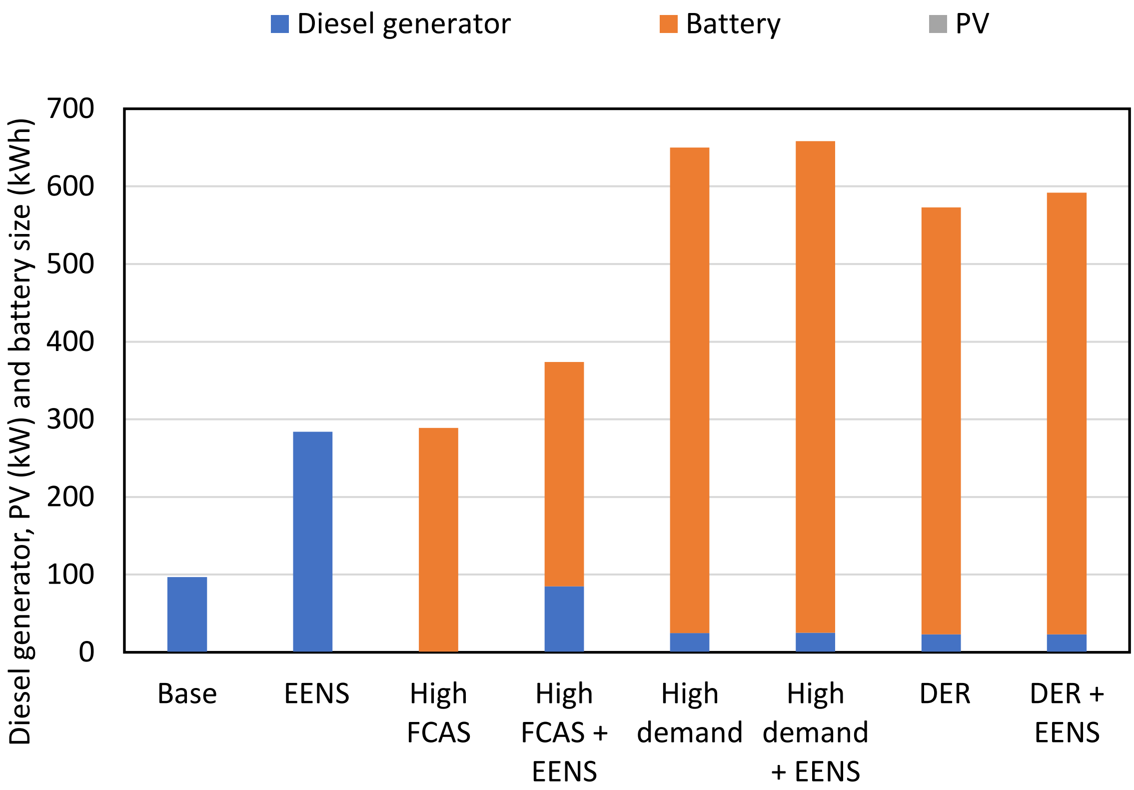


Figure 47. Investment in the different DER for the different scenarios using the Central wholesale market price scenario for a microgrid in Tarnagulla.

The results in Figure 48 represent the impact of different scenarios in the investment decisions in Tarnagulla under the assumptions behind the High and Volatile wholesale market price scenario Overall, when compared to the Central wholesale market price scenario, the required investment in DER is higher. Like the results for the Central wholesale market price scenario, presented in Figure 47, there is limited need to invest in PV systems, with the exception of the high demand scenario. It must be noted the results only display battery capacity installed, as in all scenarios the battery installed have a duration of approximately 1 hour. Additionally, due to high and volatile prices driving further investment in DER the differences on investment required between considering the impact of bushfires in the investment decision are reduced when compared to the Central wholesale market price scenario. Overall, the high and volatile wholesale market price (with many periods with prices higher than $300/MWh) prioritizes the investment in diesel generator to provide wholesale market arbitrage in all case studies. However, there is value on investing in battery systems in all scenarios as well.

While the investment decisions change between the two wholesale market price scenarios, similar conclusions can be extracted. For instance, high FCAS prices make batteries a desirable asset to participate in this market, and high demand and increased DER provide somewhat similar investment decisions. In this case, high demand scenario requires large diesel generators to provide wholesale market arbitrage for higher energy demand. This is the only case in which investment in PV is recommended, as the higher demand combined with high prices and the lower operational costs of PV, makes PV a desirable investment, which combined with storage can provide wholesale market arbitrage in this higher demand case study. Interestingly, the high demand conditions result in the most significant change when considering the impact of bushfires. According to the parametric study in Project 7, PV systems are the most beneficial DER in terms of reducing the EENS. Therefore, when accounting for the risks of bushfires, the PV capacity installed significantly increases in detriment of the battery storage installed, which has less impact reducing the EENS.

In the case of increased DER in the system, PV investment is no longer required, as the customer-owned PV significantly increases, providing enough PV capacity installed in the microgrid. When compared to the base case study, the increased DER results in similar investment decisions, with marginally larger batteries to support the microgrid operation during bushfires.

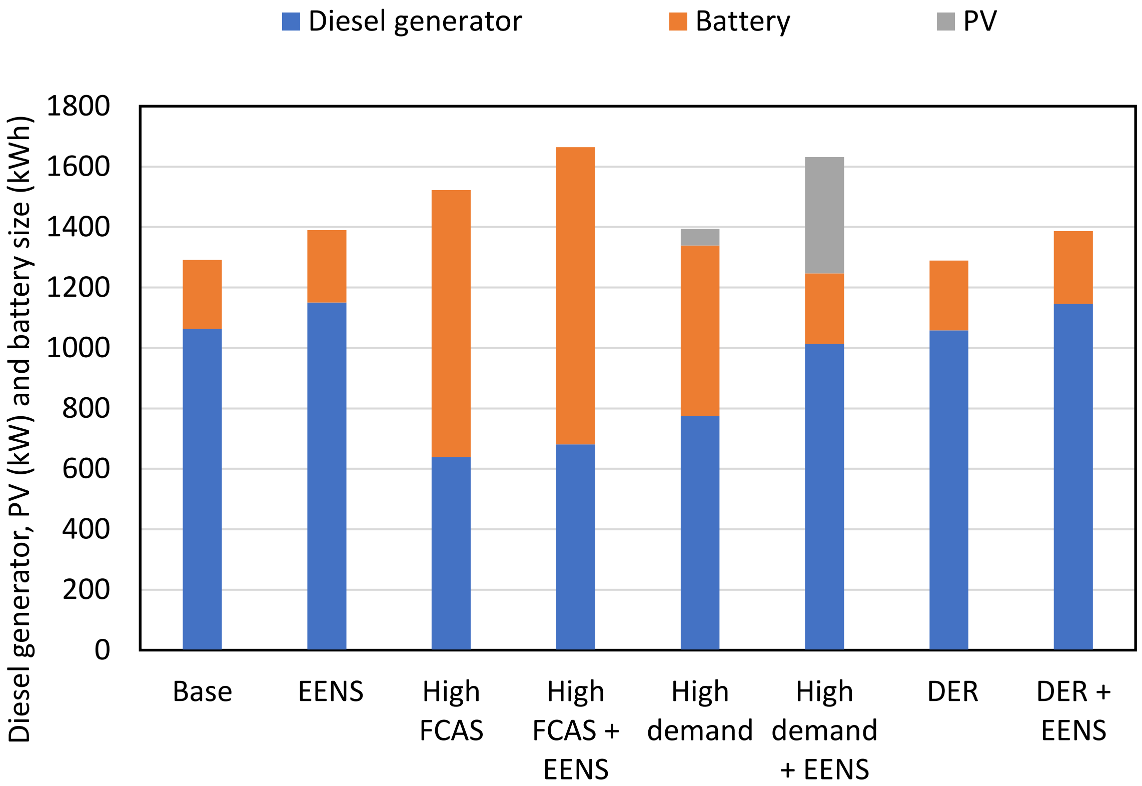


Figure 48. Investment in the different DER for the different scenarios using the High and Volatile wholesale market price scenario for a microgrid in Tarnagulla.

4.1.1.2 DER Location in the MV network

As the investment model includes the MV network, in addition to the total investment size of the different DER technologies, it can inform on the more appropriate locations to install these DER. As mentioned in Section 2.3.2, the DER can be located either at the PCC of the microgrid or the LV side of the MV/LV transformers and there is no limit in the number of DER that can be connected in the network.

Table 11 summarizes the frequency in which a particular location in the MV network was selected to install the largest microgrid DER for each specific technology. The results highlight that two locations are most adequate to install the microgrid DER: either at the point of connection of the microgrid with the upstream grid “PCC”, or in the LV side of the the MV/LV transformer “Poverty 1E”. The details of the MV network topology considered can be found in Section 3.3.

Table 11. Frequency in which the investment model selected various locations to install the largest DER for the different DER technologies

Location	PV	Diesel Generator	Battery
PCC	1	8	6
Poverty 1E	1	3	8
Reserve 3	0	1	0
Victoria P7	0	2	0
Tarnagulla	0	1	0

4.1.1.3 Illustrative case: stochastic investment decisions

The previous investment decisions were based on deterministic analysis of uncertainty. That is, selecting the optimal investment decisions for a specific realization of uncertainty (e.g., a specific scenario). However, there is value on including in the investment decisions the impact of uncertainty. This is done by making stochastic decisions e.g., making the optimal investment decision to withstand two or more future scenarios that might take place with a given probability.

A single investment decision is selected to maximize the expected NPV, which in the case of considering two scenarios is defined as the sum of the NPV of each scenario $(s1, s2)$ multiplied by its probability (p_{s1}, p_{s2}).

$$Expected\ NPV\ = p_{s1} NPV_{s1} + p_{s2} NPV_{s2}$$

The impact of including uncertainty on investment decisions (i.e., stochastic decisions) is presented in Figure 49. The results presented first display the deterministic decisions in the case study including the scenario of high customer demand with bushfire risk (High Demand + EENS) for each wholesale market price scenario (Central, and High and Volatile Price). Then, the stochastic decision is presented, where investment decisions are made to maximize the expected NPV considering both wholesale market price scenarios with a probability of occurrence equal to 50%. This specific case study was selected since the Central and High and Volatile Prices scenarios result in significantly different decisions, and the High and Volatile scenario is the only case study in which investment in PV is recommended.

When comparing the deterministic decisions for each scenario to the stochastic decisions, it is clear that the resulting investment decision considering uncertainty (Stochastic) is not the “average” investment decision of both scenarios. This demonstrates the importance of investment analysis considering uncertainty, as the stochastic investment decisions cannot be directly inferred from the deterministic decisions (i.e., stochastic decisions are not an average of both deterministic decisions).

The stochastic decisions have more similarities with the High and Volatile price scenario than the Central Scenario, with slightly lower total DER installed capacity when compared to the High and Volatile price scenario. This occurs because in the High and Volatile price scenario, there are high costs associated with purchasing energy from the wholesale market to meet the increased local demand, as well as considerable opportunities for DER to sell energy and accrue significant revenues. These higher revenues and costs, when considered stochastically with the lower revenues and costs arising from the Central wholesale market price scenario, yield to similar investment decisions to the deterministic High and Volatile price scenario. That is, the stochastic decision considers that if the investment decisions were selected to accommodate the Central scenario, the costs in the High and Volatile price scenario would be too high, whereas investment decisions closer to the High and Volatile price scenario will control the costs if the High and Volatile price scenario take place, while producing acceptable results in the Central scenario, where DER can still accrue some revenues, reduce costs from purchasing energy in the wholesale market, and reduce the costs of EENS. The stochastic decisions results in lower investment in diesel generator and battery when compared to the High and Volatile price scenario, which is expected as this is a direct impact of considering stochastically both scenarios, where the Central scenario requires lower DER capacity installed than in the High and Volatile price scenario. Interestingly, we see higher investment in PV than in the deterministic decision for the High and Volatile price scenario, whereas the Central scenario did not recommend investing on this technology. This also displays the potential of stochastic decisions that consider uncertainty when making decisions. While a technology might not be optimal for a specific scenario, once uncertainty is accounted for this technology might perform better in both scenarios than the technologies originally recommended in the deterministic analysis.

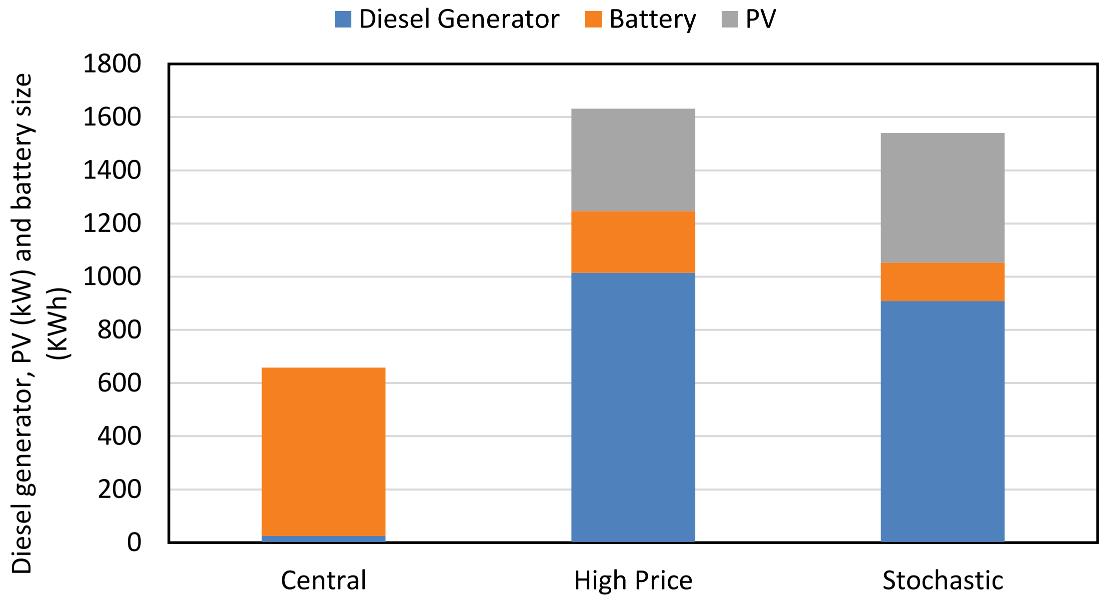


Figure 49. Comparison of deterministic decisions (Central and High Price) for the High demand + EENS case study and decisions including uncertainty in wholesale market prices with equal probability (Stochastic) in Tarnagulla.

4.1.1.4 Illustrative case: the cost of environment-conscious decisions

As discussed in the survey presented in Section 3.1. there is value on considering environmental aspects in the microgrid investment. Therefore, for the next illustrative case, investment in diesel generator is not allowed. This case is performed for the High Demand case study, for both wholesale market price scenarios.

The results in Figure 50 present how the investment decisions change when diesel generators are not considered as an investment option due to environmental concerns within the community. In the case of the Central wholesale market price scenario this results in overall higher investment in DER, with higher investment in battery technology. Interestingly, in the High and Volatile price scenario the total investment in the microgrid DER is reduced when diesel generators are not an investment option. This displays that there is a limitation on the value the combination of PV + battery storage can accrue in conditions of high and volatile wholesale market prices, when compared to diesel generators. Diesel generators present low fixed OPEX (per MW installed), and if wholesale market prices are considerably higher than $300/MWh (diesel generator fuel cost) with enough frequency the diesel generator can be dispatched to provide significant value through arbitrage. On the other hand, PV cannot be operated in that manner, as it depends on the solar irradiance profiles; and batteries need to be charged by excess PV or by purchasing energy at times of low wholesale prices to then export at times of wholesale market prices. Therefore, the overall optimal investment is lower, as at some point the possible benefits from higher PV + battery installed outweigh the benefits. It is important to highlight that this results arise from the CAPEX and OPEX assumption for batteries; these costs have displayed a consistent decreasing trend in the last decade and thus, in the future with lower battery costs, further investment on batteries might be recommended.

The lifetime economic results are presented in Figure 51 comparing the case with and without diesel generators. For both Central and High and Volatile scenarios, the total lifetime costs and benefits result in a reduction on the total net position of the microgrid when diesel generators are not considered. The economic results the High and Volatile scenarios highlight that diesel generators involve high costs in fuel (and therefore, high environmental impact) but result in significant market revenues. When diesel generators are not installed in the microgrid, fuel costs are avoided, but market revenues are considerably reduced. Given the economic data (CAPEX and OPEX) presented in Table 6, investment and operational costs are higher when diesel generators are not considered, as it is the cheapest resource. However, the economic results present the additional cost of fuel, which was assumed constant at $300/MWh. This assumption neglects that fuel costs might vary in the next years, as well as other additional costs related to environment regulation might arise (e.g., carbon taxes) and not relying on diesel generators allows the microgrid to become independent on an additional source of uncertainty.

It must be highlighted that if fuel costs (and additional regulatory costs such as carbon taxes) during the span of the economic assessment were equal to $486/MWh in the Central wholesale price scenario, and $600/MWh in the High and Volatile price scenario, the total lifetime costs and benefits of both cases (investing on diesel generators or not) would be the same, resulting in equal net positions for both cases.

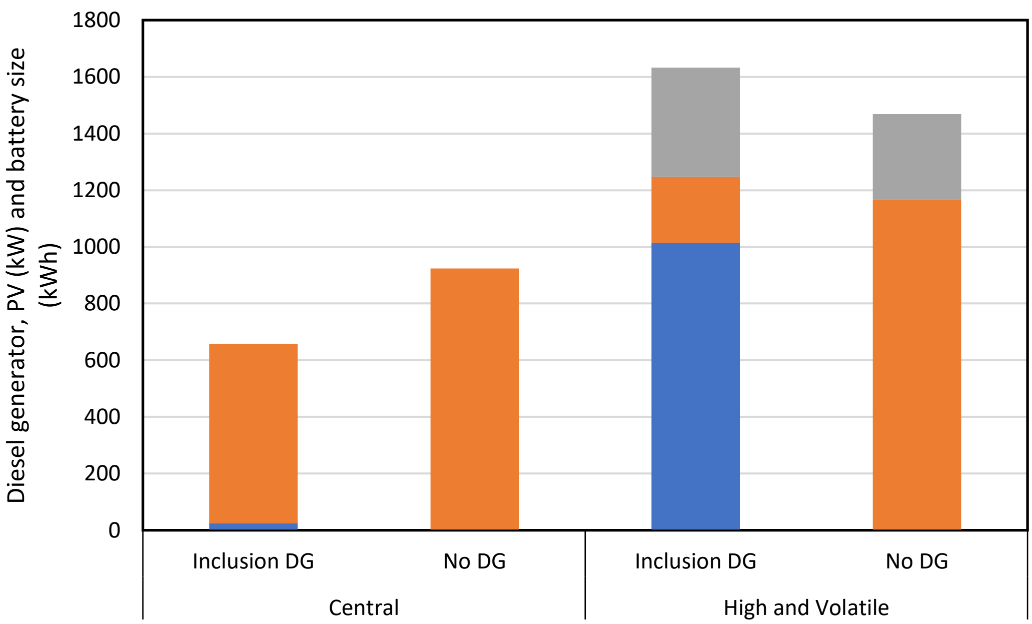


Figure 50. Comparison of the investment decisions in Tarnagulla if the diesel generator is an investment option (Inclusion DG) or if the diesel generator is not an investment option (No DG) for the High Demand + EENS case study and both wholesale market price scenarios.

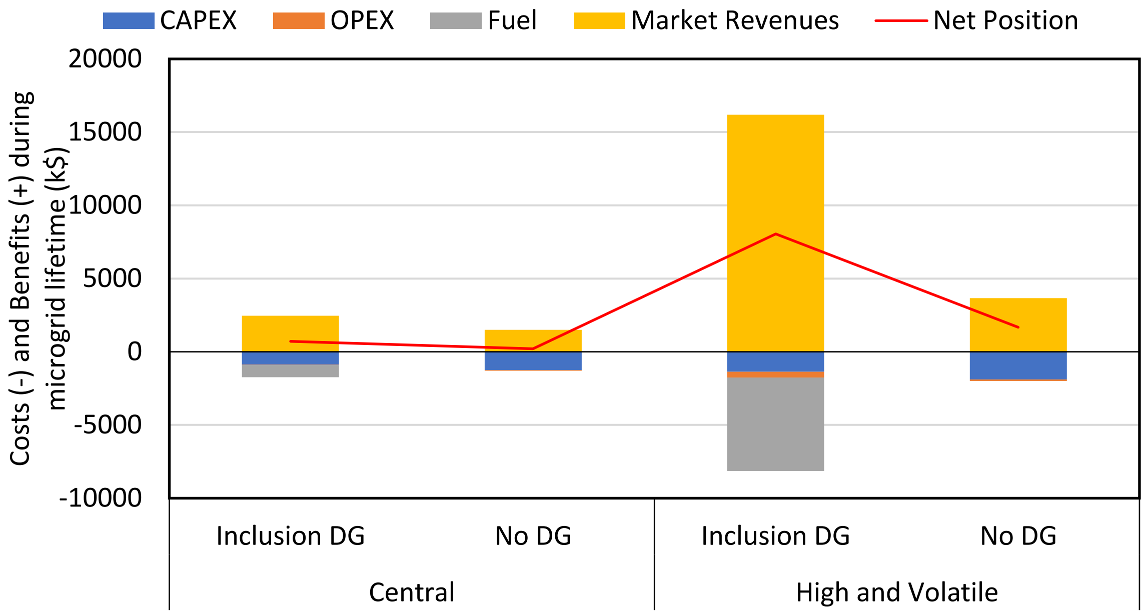


Figure 51. Comparison of microgrid costs in Tarnagulla if the diesel generator is an investment option (Inclusion DG) or if the diesel generator is not an investment option (No DG) for the High Demand + EENS case study and both wholesale market price scenarios.

4.1.2 Investment Results for a microgrid located in Donald

4.1.2.1 Deterministic investment analysis

The Donald microgrid investment decisions for the case studies defined by Table 9 and Table 10 are presented in Figure 52 and Figure 53, respectively.

The results in Figure 52 represent the impact of different scenarios in the investment decisions in Donald under the assumptions behind the Central wholesale market price scenario (lower prices and limited price volatility). Importantly, the results display that PV investment is generally not recommended, like in the case of Tarnagulla. Only in the case of High FCAS prices PV investment is recommended, as PV can participate in FCAS, especially in lower services. However, the general lack of investment on PV is explained by the same reasons as Tarnagulla, the presence of customer-owned PV and price spikes that do not occur at times of high PV generation, therefore the value additional PV can provide is limited.

When comparing the investment results for Donald and Tarnagulla the required higher investment for Donald is clear. This is expected, as the Donald area serves more customers, presenter larger demand and the MV network is significantly larger, where local generation can meet local demand as well as reducing losses. It must be noted the results only display battery capacity installed, for the different scenarios. The microgrid integrated investment and operation model consistently selects batteries with a duration for approximately 2 hours in the Central wholesale market price scenario, and for the High and Volatile scenario, selects with a duration of approximately 1 hour.

Donald's investment decisions are mainly affected by wholesale market price scenarios, where the different case studies presented (e.g., higher FCAS prices, demand, increased DER) for a given wholesale market price scenario do not provide significant differences. Essentially the main difference between the case studies for the Central and High and Volatile wholesale market price scenario is the amount of required investment and the relative size of diesel generators and batteries required. In the central scenario, larger batteries dominate the investment required, with relatively smaller diesel generators to supply energy locally during price spikes. In the High and Volatile wholesale market price scenario, price spikes occur more often, and larger diesel generators are needed to reduce the impact of these high prices, whereas batteries are mainly used to absorb excess PV, while also supporting the diesel generator discharging when high demand coincides with price spikes.

Regarding the impact of including bushfires, as opposed to the case of Tarnagulla, investment decisions remain mainly unaltered by the inclusion of the parametric study carried out in Project 7. This is mainly due to the fact that the sizes tested in Project 7 ranged from 0.5 MW to 2 MW for diesel generator and PV systems, and for battery systems from 0.5 MWh to 2 MWh. Just considering the normal operation of the microgrid, the optimal investment is larger than this range studied in Project 7. Therefore, normal operation of the microgrid drives the need to invest and with virtually the same investment decision the EENS costs are controlled when considering bushfires.

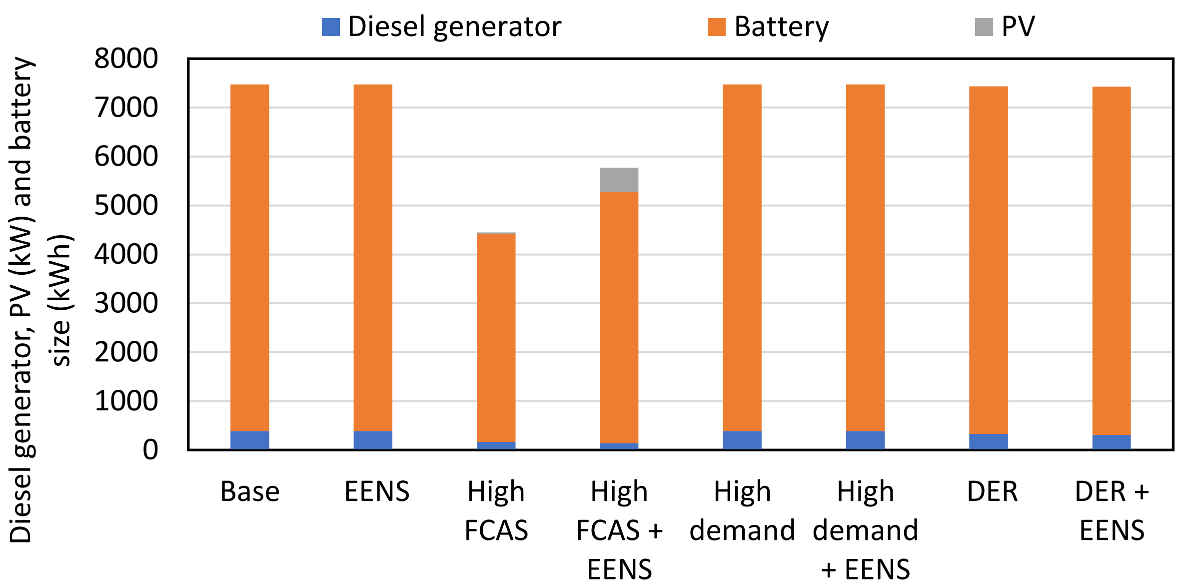


Figure 52 . Investment in the different DER for the different scenarios using the Central wholesale market price scenario for a microgrid in Donald.

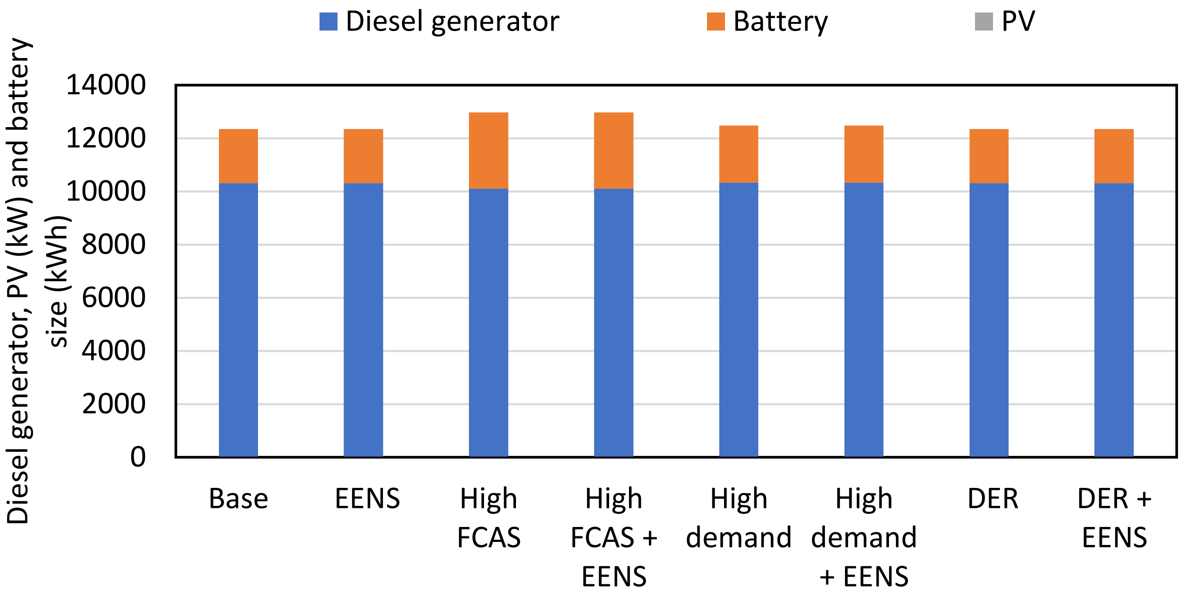


Figure 53. Investment in the different DER for the different scenarios using the High and Volatile wholesale market price scenario for a microgrid in Donald.

4.1.2.2 DER Location in the MV network

As the investment model includes the MV network, in addition to the total investment size of the different DER technologies, it can inform on the more appropriate locations to install these DER. As mentioned in Section 2.3.2, the DER can be located either at the PCC of the microgrid or the LV side of the MV/LV transformers and there is no limit in the number of DER that can be connected in the network.

Table 12 summarizes the frequency in which a particular location in the MV network was selected to install the largest microgrid DER for each specific technology. As Donald is a larger network, there are more options in which DER can be installed, and the most appropriate location of DER is less clear than in the case of Tarnagulla. However, the PCC location is preferrable for both diesel generator and batteries, as it displays the highest frequencies. The details of the MV network topology considered can be found in Section 3.3.

Table 12. Frequency in which the investment model selected various locations to install the largest DER for the different DER technologies

Location	PV	Diesel Generator	Battery
PCC	0	6	8
Aitken Sproats	0	2	2
Kooka	0	2	0
Racecourse Harbergers	0	2	0
McConville 4	1	0	0
Harbergers P1	1	0	0
Jeffcot RD2	0	2	0
McCulloch Woods	0	0	3
McCracken Camp	0	0	1
Donald Pump 1&2	0	0	2
Woods Oakley 4	0	1	0
Donald 385	0	1	0

4.1.2.3 Illustrative case: stochastic investment decisions

The impact of including uncertainty on investment decisions (i.e., stochastic decisions) for Donald is presented in Figure 54. Like for the case of Tarnagulla, the case study of high customer demand with bushfire risk (High Demand + EENS) is considered for each wholesale market price scenario (Central, and High and Volatile Price). Then, the stochastic decision is presented, where investment decisions aim to maximize the expected NPV considering both wholesale market price scenarios with a probability of occurrence equal to 50%.

When comparing the deterministic decisions for each scenario to the stochastic decisions, it is clear that the resulting investment decision considering uncertainty (Stochastic) is not the "average" investment decision of both scenarios, and similar conclusions to the case of Tarnagulla can be extracted. The High and Volatile scenario with higher costs and revenues dominates the stochastic decisions, significantly increasing the diesel generator size when compared to the Central wholesale market price scenario. However, battery system size increases with respect to the High and Volatile scenario, as this resource is better suited for the Central scenario. PV investment is not recommended in the stochastic decision. Again, these results demonstrate the importance of investment analysis considering uncertainty, as the stochastic investment decisions cannot be directly inferred from the deterministic decisions (i.e., stochastic decisions are not an average of both deterministic decisions).

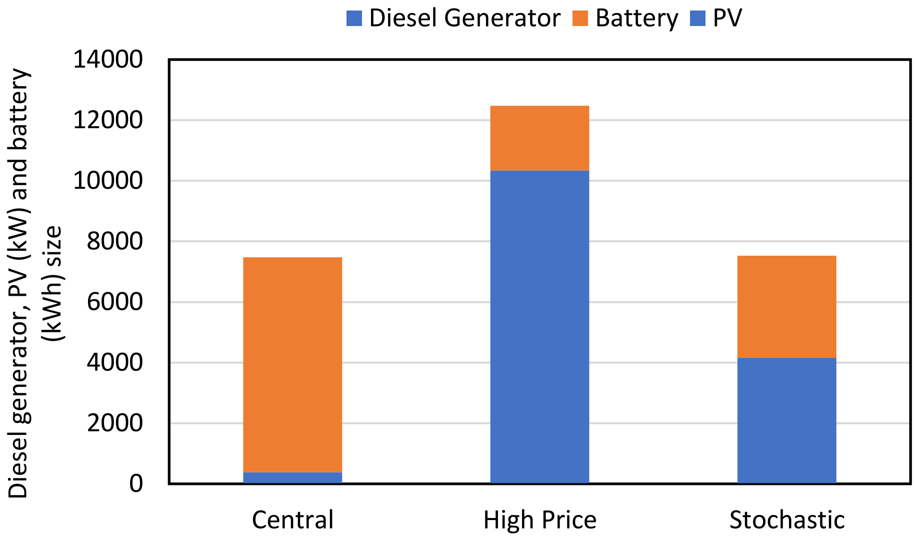


Figure 54. Comparison of deterministic decisions (Central and High Price) for the High demand + EENS case study and decisions including uncertainty in wholesale market prices with equal probability (Stochastic) in Donald.

4.1.2.4 Illustrative case: the cost of environment-conscious decisions

As in the case of Tarnagulla, there is an interest on understanding the impact on the microgrid investment decisions and resulting costs and benefits when the environmental implications of installing diesel generators are considered.

The following study is performed for the High Demand + EENS case, for both wholesale market price scenarios. The investment decisions for the microgrid in Donald are presented in Figure 55, displaying equivalent results than the ones presented for Tarnagulla. When diesel generators are not considered an investment option, battery technologies are prioritized, with very limited investment on PV for the High and Volatile price scenario. The same behaviour in terms of total DER installed is present, as in the High and Volatile price scenario when not including diesel generators, lower total investment is recommended for the same reasons as Tarnagulla (i.e., costs of being able to fully benefit from the frequent price spikes in the wholesale market with the combination of PV and battery outweigh the benefits).

Figure 56 presents the Donald microgrid total costs and benefits as well as the net economic position of the microgrid. These economic results are presented for both wholesale market price scenarios when diesel generator is included as an investment option and when diesel generators are not considered as an investment option. Equivalent conclusions than the ones detailed for Tarnagulla can be extracted for Donald. Overall, the environmental considerations come with an additional cost (or reduced benefits) for the microgrid, especially for the High and Volatile wholesale market price scenario. In the central scenario, the net position of the microgrid is only slightly reduced as a result of not including the diesel generator. This was expected as the optimal diesel generator investment when considered as an investment option is minimal when compared to installed battery capacity.

Like in the case of Tarnagulla, the improved economic performance when including diesel generators is subject to the assumptions around fuel costs which are reflected in the lifetime fuel costs presented in Figure 56. If fuel costs during the 12 years of economic assessment were considered equal to \$341/MWh in the Central wholesale price scenario, and \$373/MWh in the High and Volatile price scenario, the total lifetime costs and benefits of both cases (investing on diesel generators or not) would be the same, resulting in equal net positions for both cases. Therefore, the case of Donald is even more sensitive to fuel costs than the case of Tarnagulla, where the fuel costs to “break-even” when not considering diesel generators are higher. This highlights that not considering diesel generators in addition to reducing the environmental impact in the community can avoid an additional source of uncertainty which are fuel costs or future costs arising from regulatory developments aiming to reduce carbon emissions.

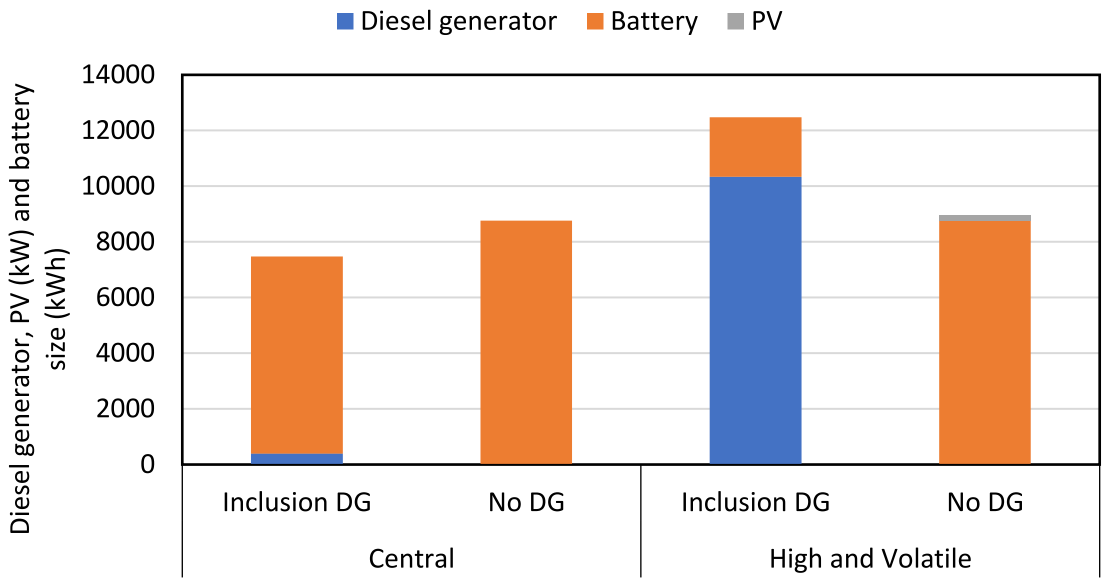


Figure 55. Comparison of the investment decisions in Donald if the diesel generator is an investment option (Inclusion DG) or if the diesel generator is not an investment option (No DG) for the High Demand + EENS case study and both wholesale market price scenarios.

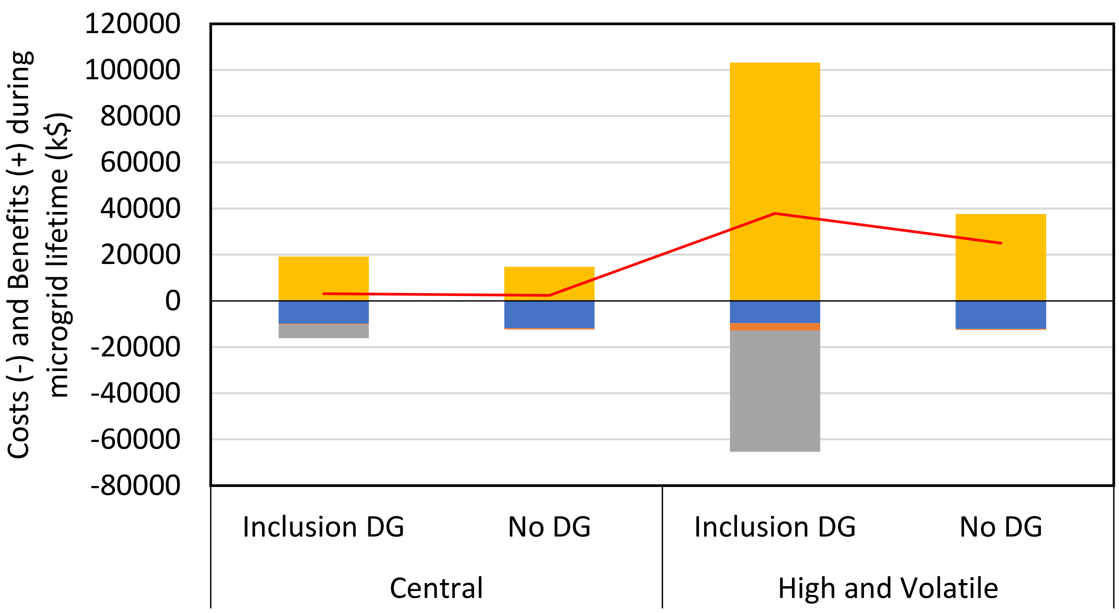


Figure 56. Comparison of microgrid costs in Donald if the diesel generator is an investment option (Inclusion DG) or if the diesel generator is not an investment option (No DG) for the High Demand + EENS case study and both wholesale market price scenarios.

4.1.3 Sensitivity studies

Previous deterministic and stochastic investment decisions were subject to the following assumptions:

- The inclusion of costs associated with the EENS is affected by the bushfire probability. For all cases the microgrid is designed under the assumption that two bushfires will take place during the economic assessment span (twelve years). Thus, EENS due to bushfires is included in the microgrid integrated investment and operation model using a probability equal to 2/12.
- The inclusion of the costs associated with the EENS was based on an approximation of the results from the parametric study carried out in Project 7, in which EENS in MWh/year was quantified for different microgrid DER sizes. This parametric study was carried out for different types of bushfires causing different fuel disruption scenarios. Namely, a bushfire that does not cause fuel disruption, a bushfire in which the microgrid DER have one day of fuel storage and there is a fuel disruption of five days (S1D5) and one day of fuel storage and with a fuel disruption duration of ten days (S1D10). The previous analysis used the results corresponding to bushfire that does not cause fuel disruption, as in Project 7 it was considered the most common type of bushfire.
- Ash and smoke from bushfires can reduce PV system output. However, in the main investment analysis carried out it is assumed that PV system output is unaffected by the ash and smoke from bushfires.
- The inclusion of the costs associated with the EENS was based on an approximation of the results from the parametric study carried out in Project 7, which was based on the existing penetration of customer-owned DER. In the case study considering increased customer-owned DER, it was assumed that this new installed DER did not impact the EENS results coming from Project 7 parametric study. However, customer-owned DER can effectively reduce the EENS as these are local resources that can support the operation of the microgrid and supply local demand in the event of a bushfire.

In the following sensitivity analysis, the impact these assumptions have on investment decisions will be analysed. To perform this sensitivity analysis, a microgrid in Tarnagulla under the Central wholesale market price scenario and High Demand case study is selected. Tarnagulla is chosen as a more appropriate location to carry out the sensitivity analysis on the different assumptions surrounding the impact of bushfires, as the required investment coming from deterministic and stochastic investment analysis is more aligned to the sizes tested in the parametric study in Project 7. Thus, the different assumptions surrounding the bushfire impact as modelled in Project 7 will have a more relevant effect on Tarnagulla. The high demand case is selected for all sensitivity studies with the exception of the sensitivity studies focused on increased customer-owned DER, in which the case study of increased DER is required. The High Demand case study is selected for the remaining sensitivities as this is the only case in which the original investment decision in the microgrid included PV systems, and therefor can display the impact of the above-mentioned assumptions on the investment decisions on the three DER technologies considered.

4.1.3.1 The impact of different bushfires probabilities on investment decisions

In the results presented in Section 4.1.1.1, the impact of bushfires was analysed under the assumption that during the economic assessment span there will be two years in which bushfires will take place. Therefore, the impact of bushfires is included in the microgrid integrated investment and operation model with a probability equal to 2/12. However, investment decisions will be impacted by the bushfire probability. In this sensitivity analysis, the impact this probability of occurrence of bushfires on investment decisions is analysed. This is done by increasing the expected number of years in which bushfires take place, displaying the evolution on investment decisions from not considering any bushfires to considering that every year in the economic assessment horizon there will be a bushfire. The latter implies that EENS costs are included in the microgrid integrated investment and operation model with a probability equal to one (12/12).

The results are presented in Figure 57, with the x-axis representing the design assumption regarding the number of years in which bushfires will take place during the economic assessment horizon. This indirectly represents the probability in which the impact of bushfires is included in the microgrid integrated investment and operation model. Figure 57 represents how investment decisions change in Tarnagulla as the design considers higher occurrence of bushfires. The results display that when bushfires occur more often, higher investment on PV results advantageous. The diesel generator required investment remains fairly constant as the bushfire probability increases, whereas investment on battery systems slightly reduces. The results also highlight that at first there are considerable differences on the investment decision when increasing the bushfire probability, but at high probability of occurrence the investment decisions remain similar. Namely, considering 10 years and 12 years in which bushfires take place yields the same investment decision. Overall, the results accurately display the behaviour presented in the parametric study carried out in Project 7, which displayed that PV is the DER technology that more efficiently reduces the EENS.

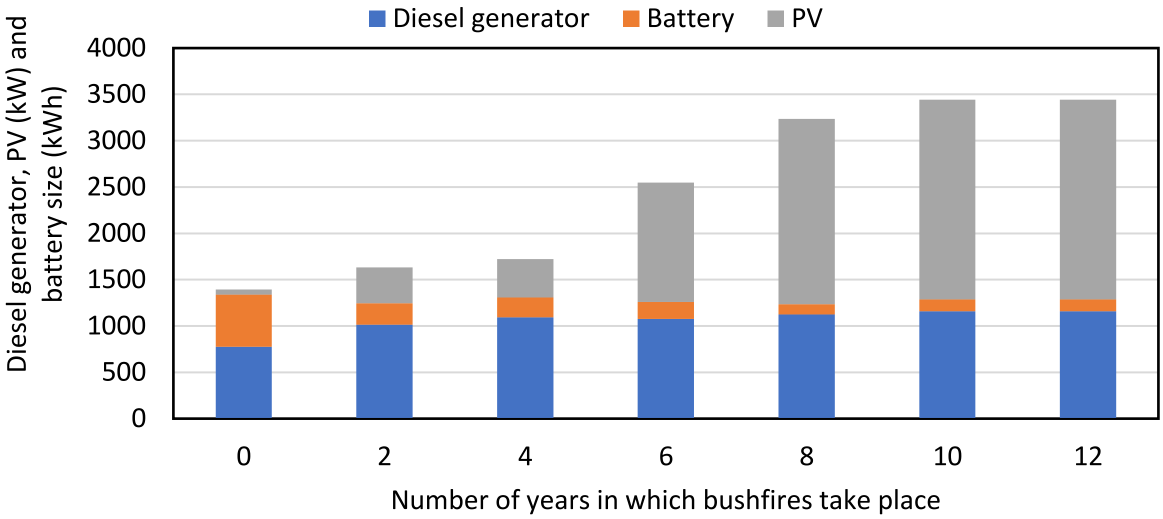


Figure 57. Comparison of investment decisions considering different bushfires probabilities on the High demand + EENS case study under the High and Volatile wholesale market price scenario for a microgrid in Tarnagulla.

4.1.3.2 The impact of different type of bushfires on investment decisions

The main analysis on investment decisions used the results from the parametric study carried out in Project 7, in which EENS in MWh/year was quantified for different DER sizes, under the assumption of a bushfire that does not cause fuel disruption. However, the parametric studies in Project 7 considered different type of bushfires. Specifically, it analysed the impact of different fuel disruption scenarios. Namely, having one day of storage and suffering a fuel disruption of five days (S1D5) and having one day of storage and suffering a fuel disruption of ten days (S1D10).

In this sensitivity analysis the impact on investment decisions when considering different fuel disruption scenarios is analysed for two extreme assumptions. First, microgrid design assumes that only two bushfires will take place during the economic assessment horizon (EENS costs included with a probability 2/12) which is presented in Figure 58. Then, microgrid design assumes that every year a bushfire will take place (EENS costs included with a probability equal to one), which is presented in Figure 59.

The results from the parametric study in Project 7 did not result on dramatic changes on EENS with different fuel disruption scenarios. Therefore, the results in Figure 58 when considering only two bushfires in the economic assessment horizon do not display considerable differences between no fuel disruption, S1D5 and S1D10. However, when designing the microgrid considering one bushfire every year, the various fuel disruption scenarios result in more considerable differences, as displayed by Figure 59. In this case, as fuel disruption becomes more severe investment on PV increases, as it has the largest impact on reducing EENS specially when fuel availability is disrupted.

The results do not only display the impact of different fuel disruption scenarios, but also highlight how the design assumptions around the probability of bushfires will impact investment decisions. When considering lower probabilities of bushfires, the investment decisions are robust to different bushfire scenarios. However, when designing a microgrid under the assumption of (very) high occurrence of bushfires, fuel disruption has a significant impact on the DER portfolio required. This effect is seen in the remaining sensitivity studies performed in the following sections.

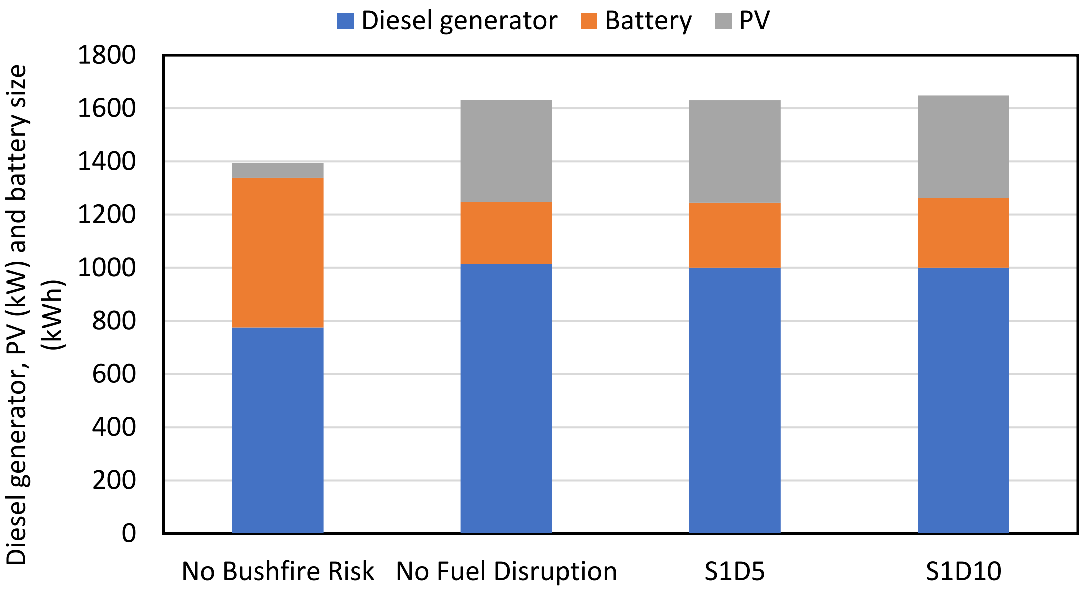


Figure 58. Comparison of investment decisions considering different fuel disruption scenarios for the High demand + EENS case study under the High and Volatile wholesale market price scenario for a microgrid in Tarnagulla (2 years with bushfires).

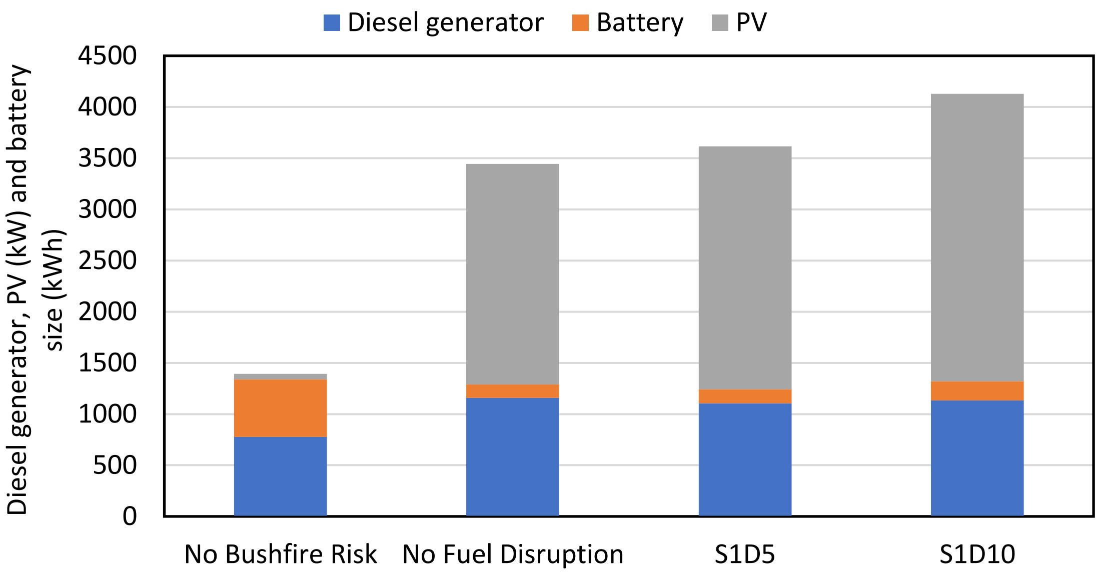


Figure 59. Comparison of investment decisions considering different fuel disruption scenarios for the High demand + EENS case study under the High and Volatile wholesale market price scenario for a microgrid in Tarnagulla (12 years with bushfires).

4.1.3.3 The impact of a reduction of PV efficiency due to bushfires

Presently, it is believed that ash and smoke from bushfires can reduce PV system output. However, in the main investment analysis carried out it is assumed that PV system output is unaffected by the ash and smoke from bushfires. In this sensitivity study the impact of a reduction of PV efficiency from 100% to 70% is studied for both design assumptions e.g., only two bushfires take place during the economic assessment horizon (probability equal to 2/12) and every year a bushfire takes place (probability equal to one). The results are displayed in Figure 60 and Figure 61, respectively.

As in the case of different fuel disruption scenarios, the results highlight that when the probability associated with bushfires is low, the investment decisions is mainly unaffected by the reduction of PV efficiency. However, when designing the microgrid under the assumption of frequent bushfires, PV efficiency has an impact on investment decisions. Figure 61 displays that the reduction of PV efficiency during a bushfire results in higher required investment, not only on PV systems, but diesel generators and batteries as well, to compensate for the reduction on PV efficiency and its impact on the EENS costs.

It must be noted that PV efficiency even without bushfire conditions is not equal to 1. The case "PV Efficiency = 1" represents efficiency not affected by the impact of ash and smoke of bushfires i.e., equal PV efficiency during bushfires than in normal conditions. On the other hand, "PV Efficiency = 0.7" represents that PV efficiency is reduced during bushfires by 70% of the PV efficiency during normal conditions.

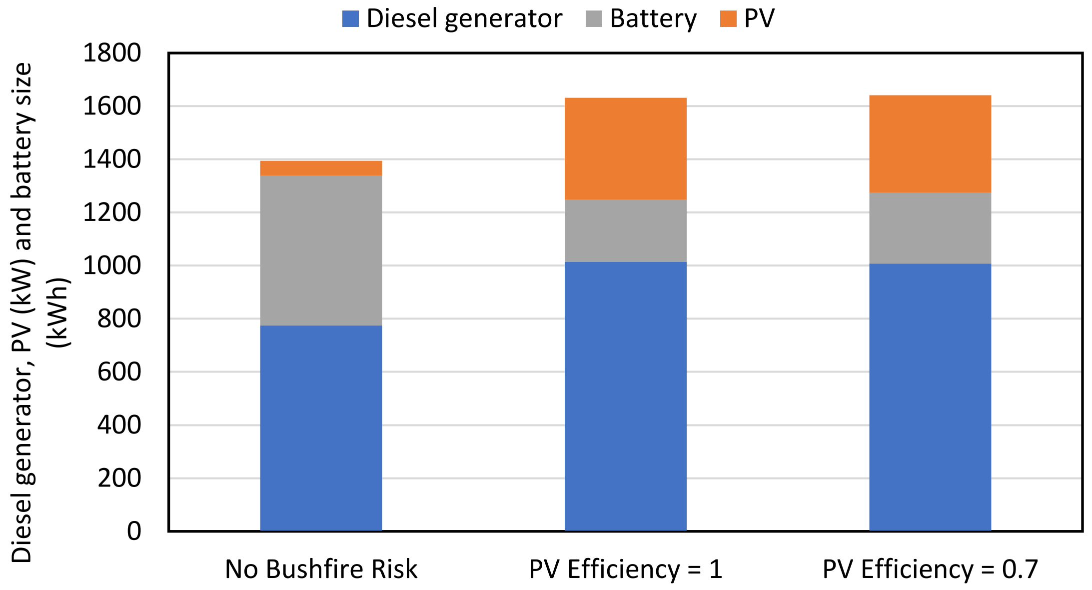


Figure 60. Comparison of investment decisions when considering the reduction of PV efficiency for the High demand + EENS case study under the High and Volatile wholesale market price scenario (2 years with bushfires).

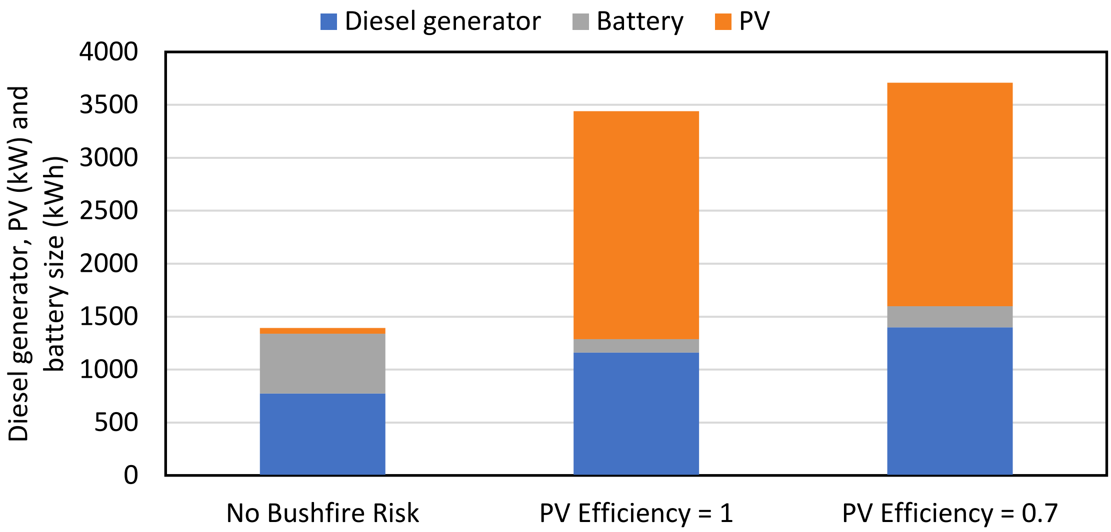


Figure 61. Comparison of investment decisions when considering the reduction of PV efficiency for the High demand + EENS case study under the High and Volatile wholesale market price scenario (12 years with bushfires).

4.1.3.4 The impact of customer-owned DER on investment decisions

The main analysis on investment decisions used the results from the parametric study carried out in Project 7, which was performed with the current customer-owned DER installed in each town. In the case study that considered increased customer-owned DER, it was assumed that this new installed DER did not impact the EENS coming from Project 7 parametric study. However, customer-owned DER can effectively reduce the EENS as these are local resources that can support the operation of the microgrid and supply local demand in the event of a bushfire.

In the following sensitivity analysis, a 30% penetration of customer-owned PV systems and 15% penetration of customer-owned battery systems is accounted as DER capacity that can reduce the impact of a bushfire, effectively reducing the EENS in the same way as microgrid DER. This assumption results in an additional 510kW of installed customer-owned PV and 492kWh of installed customer-owned battery systems, that can support microgrid operation in the event of a bushfire. In Figure 62 microgrid design assumes that only two bushfires will take place during the economic assessment horizon (EENS costs included with a probability 2/12). In Figure 63 microgrid design assumes that every year a bushfire will take place (EENS costs included with a probability equal to one).

The results display that when designing the microgrid to sustain a low probability of bushfire occurrence, the investment decisions are unaffected by the additional DER installed capacity coming from customer-owned DER, as Figure 62 shows. However, when design considers a high probability of bushfire occurrence, considering the additional DER capacity of customer-owned DER significantly reduces the required investment on PV systems. The results highlight that when designing a microgrid to sustain the risk of frequent bushfires, considering customer-owned DER can lead to a relevant reduction on required investment, and synergies arise from customer-owned DER and the microgrid DER.

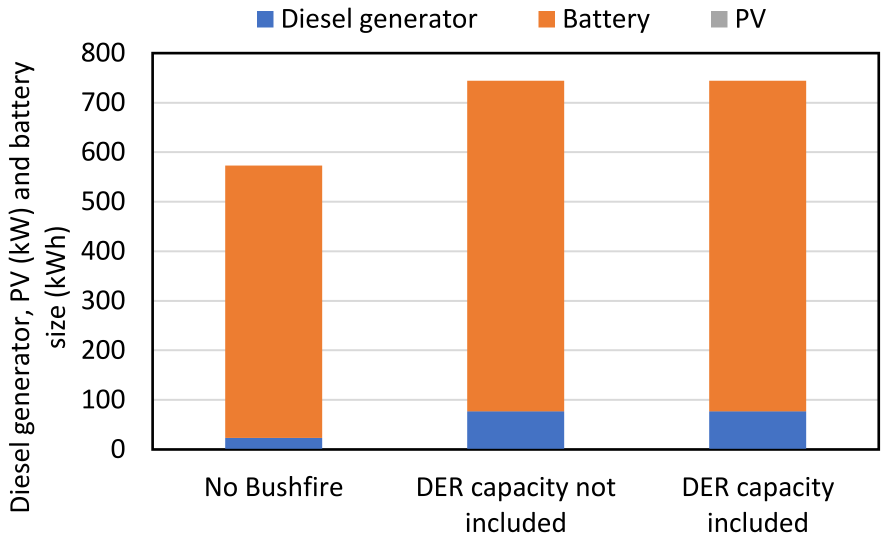


Figure 62. Comparison of investment decisions when considering the installed customer-owned DER capacity for the Increased DER + EENS case study under the High and Volatile wholesale market price scenario (2 years with bushfires).

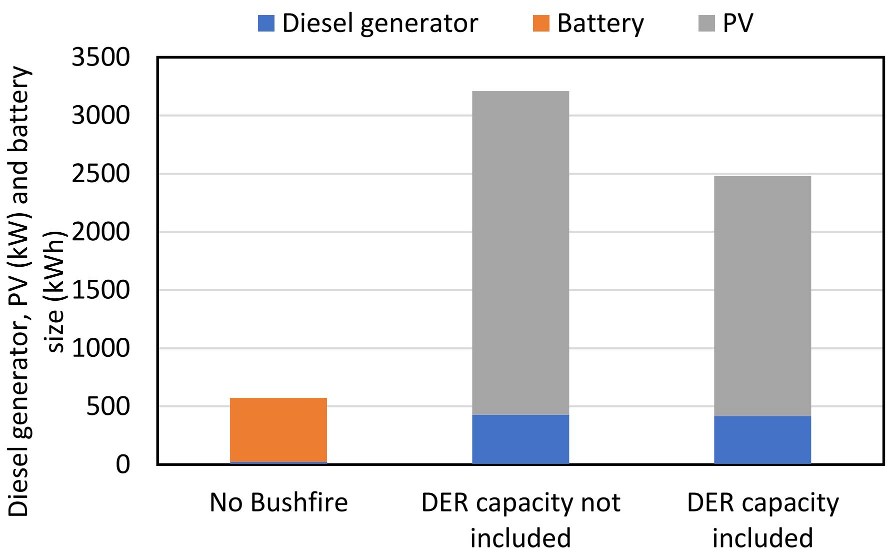


Figure 63. Comparison of investment decisions when considering the installed customer-owned DER capacity for the Increased DER + EENS case study under the High and Volatile wholesale market price scenario (12 years with bushfires).

4.1.4 Direct inclusion of bushfires: Energy not served

Previous investment analyses displayed investment decisions considering the future realisation of an uncertain parameter (scenarios) while including the impact of different microgrid DER sizes in the EENS, using the parametric studies from Project 7.

However, microgrids can be directly designed for bushfire conditions. As opposed to designing the microgrid based on *expected* energy not served, which is already affected by probabilities and measured in MWh/year, a bushfire event might be directly included in the microgrid integrated investment and operation model input data, so that the investment decisions directly reduce the energy not served (not EENS) during the bushfire event.

The following analysis considers investment in a microgrid in Tarnagulla and Donald for a two-week bushfire taking place every year, for the high demand scenario. Additionally, this analysis could be also applied to not only to actual bushfires, but high bushfire risk periods, in which de-energizing the lines connecting both towns to the upstream grid might effectively reduce the risk of bushfire events caused by active lines in the network. During these two-weeks event Tarnagulla and Donald are not connected to the upstream grid. As discussed in Project 7, the highest bushfire risk in both towns takes place between the 20th of January and 2nd of February. Therefore, for this analysis it is assumed that bushfires take place during summer. Additionally, during the time of the bushfire it is assumed the demand in Tarnagulla and Donald corresponds to the maximum demand design day conditions whereas customer-owned PV generation corresponds to the maximum PV generation, as presented in Section 3.2.1.3. However, customer-owned PV efficiency is reduced to 70%, as a conservative approach to include the effect of the bushfire smoke and ash or PV efficiency reduction due to high temperatures. Finally, it must be noted that in this analysis possible reliability issues of local resources are not considered.

The results presented in Figure 64 and Figure 65 compare four cases, all directly including two-week bushfires every year. In the first two case “two-week bushfire” and “two-week bushfire + fuel disruption” the microgrid is designed to sustain two-week bushfires during its lifetime, not considering “normal operation” e.g., microgrid operation when there is not a bushfire event. In “two-week bushfire” it is assumed that availability of fuel does not become an issue for the duration of the bushfire. Thus, the optimal investment decision for both towns consist of relevant investment on diesel generators. In the “two-week bushfire + fuel disruption” case the impact of fuel disruption is explored. In this case, during the first week of the bushfire, fuel for the diesel generator is available. Nevertheless, during the second week stored fuel has been fully utilized and there is no available fuel. The risk of fuel disruption during the second week of the bushfire, and the impact it can have in the energy not served, results in a shift on investment decisions. Large duration batteries are installed along with a PV system in both towns, to serve the local demand in bushfire conditions, effectively becoming independent from fuel disruptions.

In these first two cases the microgrid has been designed only accounting for the bushfire events. However, it is important to understand how the optimal investment decision changes when considering “Normal operation” that occurs during most of the economic assessment horizon as well as the 2-week bushfire events. In the next two cases, normal operation for the High demand case study in Tarnagulla, and central wholesale market price scenario is included along with the direct modelling of the two-week bushfires taking place every year. In the scenario of a two-week bushfire without fuel disruption, investment increases when considering normal operation as well as the two-week bushfire. Essentially, this shows that the two-week bushfires without fuel disruption would not be the main driver of the investment decision, and when including normal operation further investment in DER can provide value to the microgrid, as well as being able to support local operation during the bushfire. However, in the case of two-week bushfires with fuel disruption, the main driver for investment is the bushfire event, and considering normal operation of the microgrid does not significantly change the investment decisions. Importantly, in both towns, when bushfire conditions are considered, large duration storage is recommended in both cases, with durations of over 4 hours, to be able to provide demand during a long islanding event.

These results highlight how when directly including bushfire events and modelling the energy not served during the bushfire can dramatically impact the investment decision. Severe bushfire events (e.g., causing fuel disruption) will dominate the investment decision, as the costs of energy not served associated with the event will be significant when compared to the “normal operation”. Additionally, the results display a significant example of what previous analysis have shown. When bushfires probability is high, investment decisions are highly sensitive to different bushfire scenarios. In this case, by directly modelling the bushfire event, different bushfire scenarios (with and without fuel disruption) yield completely different investment decisions.

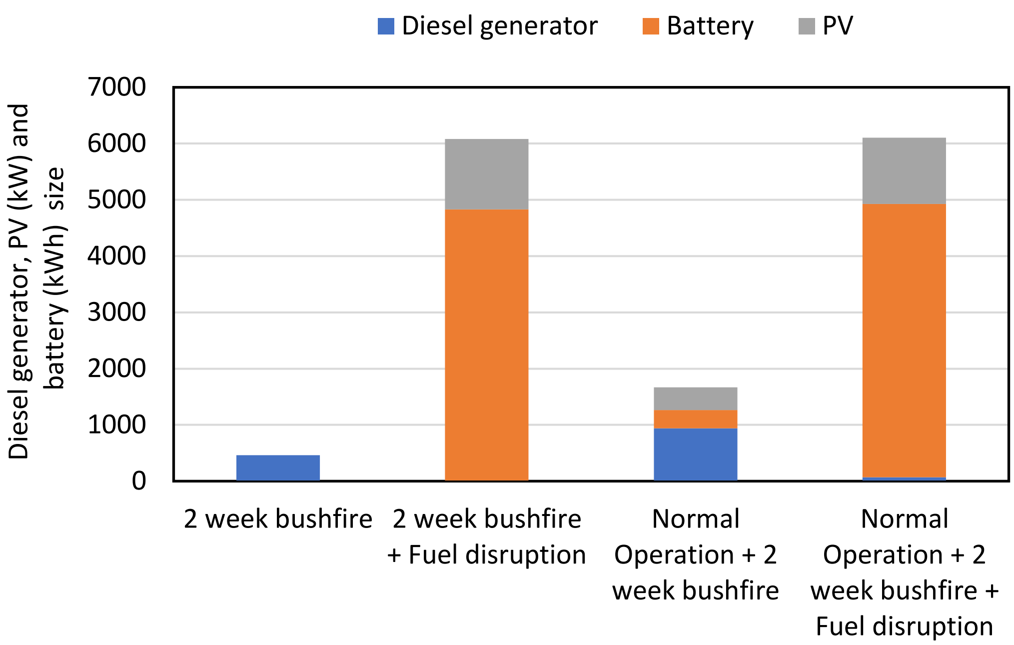


Figure 64. Comparison of investment decisions when directly including a bushfire event in the microgrid integrated investment and operation model for Tarnagulla.

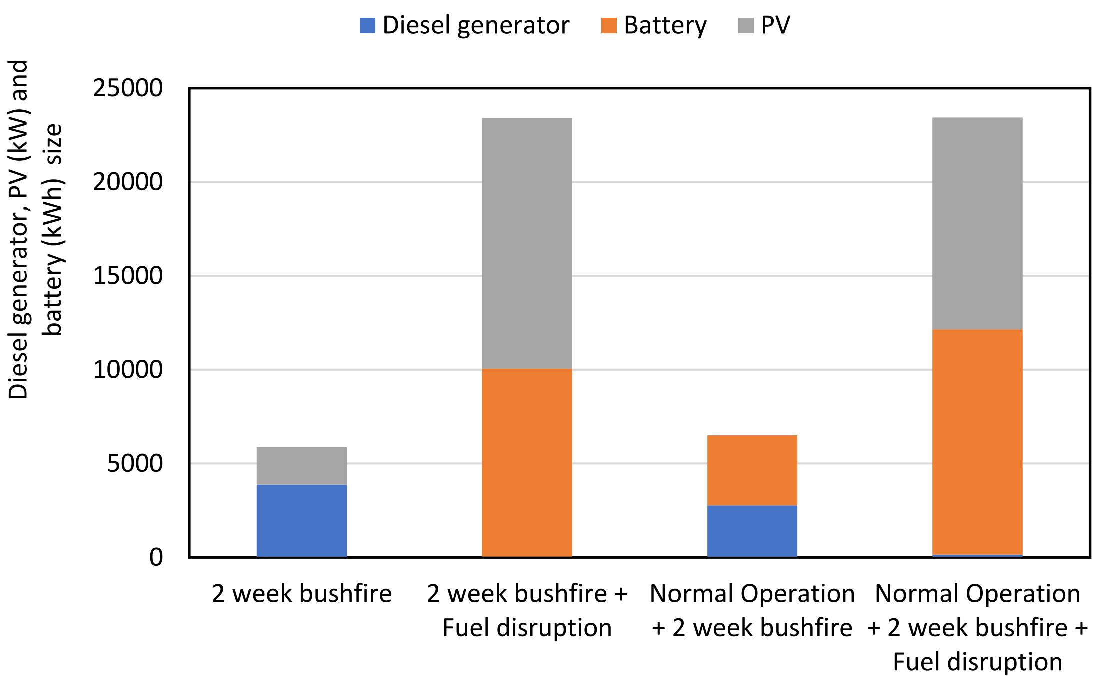


Figure 65. Comparison of investment decisions when directly including a bushfire event in the microgrid integrated investment and operation model for Donald.

4.1.4.1 Regret Analysis

In Figure 64 and Figure 65 the investment decisions resulting from directly modelling the economic impact of an extreme weather event that requires the microgrid to be islanded were presented. Designing a microgrid under this philosophy of directly modelling the impact of a bushfire as opposed to EENS is conceptually and practically significantly different. As previously mentioned, EENS utilizes probabilities to quantify the impact of extreme weather events in MWh/year, whereas when directly modelling the bushfires, there are no probabilities associated and the impact of not serving the local demand during an extreme weather event is fully accounted. These conceptual and practical differences can be clearly appreciated when comparing the optimal investment decisions from the deterministic investment decisions presented in Section 4.1.1.1 and 4.1.2.1 with the investment decisions when directly modelling bushfires in Section 4.1.4.

Given that the investment decisions presented in Section 4.1.1.1 and 4.1.2.1 did not directly consider the impact of a bushfire, but accounted for the costs associated with the EENS, it is important to understand the resulting operation of the microgrid with the recommended investment decisions during the actual bushfire. The microgrid operation during the two-week bushfire that causes fuel disruption is analysed for the various investment decision corresponding to each case study and wholesale market price scenario, and the results are presented in Figure 66 and Figure 67. The two-week bushfire that causes fuel disruption is selected as the results display this is a more severe event, effectively driving the investment decision even when considered along with the normal microgrid operation.

The performance of the optimal DER microgrid investment decision from the deterministic analysis considering EENS cost is quantified during the two-week bushfire with fuel disruption event using regrets. Regrets in (k$) represent the costs of energy not served that could have been avoided if the microgrid was designed directly modelling the bushfire, and the investment decisions were optimal to withstand the event of a two-week bushfire with fuel disruption.

The results in Figure 64 and Figure 67 represent the regrets during a single bushfire event of two weeks with fuel disruption during the second week for Tarnagulla and Donald, respectively. Overall, the results highlight that by not designing the microgrid directly modelling the energy not served during a bushfire event, if the specific bushfire event takes place significant regrets might arise. If the microgrid is designed under the central wholesale market price scenario, even when considering the EENS cost, the actual operation during the bushfire results in high costs in energy not served, and thus high regrets. The optimal decisions for the High and Volatile scenarios, recommending larger DER installed capacity, better control the energy not served costs and thus reduce regrets. However, since the battery requirements during the bushfire event are significantly larger, no investment decisions analysed present near to zero regrets.

Regarding the impact of specific DER technologies installed capacity, it must be noted that in scenarios with significant investment on diesel generator, like in the Central case study for Tarnagulla, during the first week of the bushfire (without fuel disruption) energy not served is controlled. However, once there is fuel disruption, a large amount of local demand cannot be met, and energy not served costs are high. On the other hand, batteries can charge at times of high PV exports while the diesel generator provide customer demand during the first week, prior to the fuel disruption, and can support the local demand at times of low PV generation. The benefits of this combination of diesel generator and battery is specially seen in the High and Volatile price scenarios in Donald, with relatively lower regrets than the investments tailored for the Central price scenario.

Additionally, in the cases of increased customer-owned DER, it is clear that there are significant synergies between customer-owned DER and microgrid DER that allow to significantly reduce regrets. These results display a relevant influence of customer-owned DER that was not fully captured in the results presented in the sensitivity analysis using EENS in Section 4.1.3.4. In this sense, whereas with the EENS the customer-owned DER did not have a large impact on the investment decision, when these same customer-owned DER are included in the *actual* bushfire event it results in considerably lower regrets.

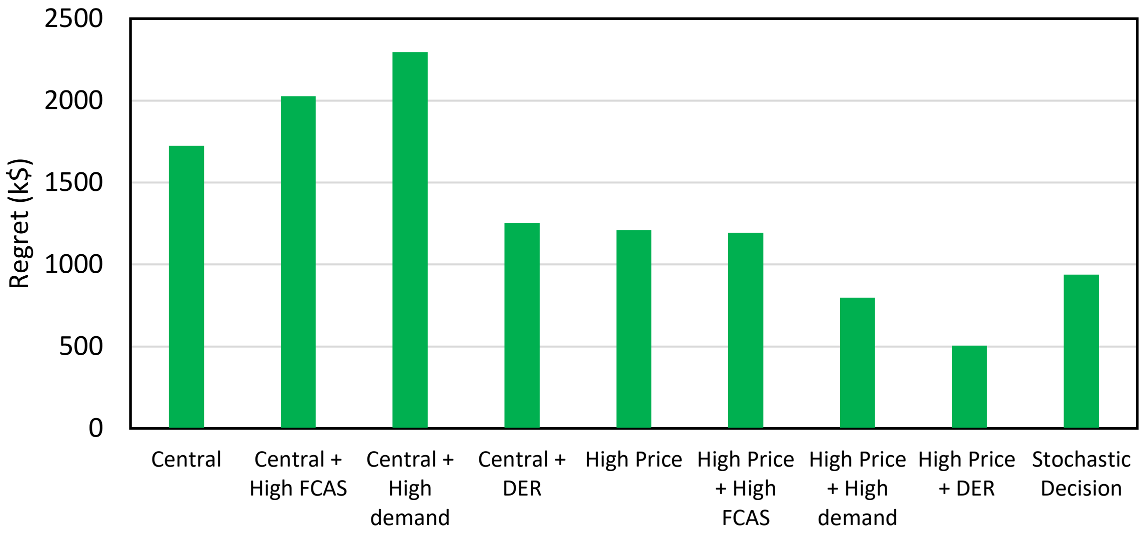


Figure 66. Regret analysis during a 2-week bushfire with fuel disruption for the investment decisions recommended in each case study including the impact of the EENS for Tarnagulla.

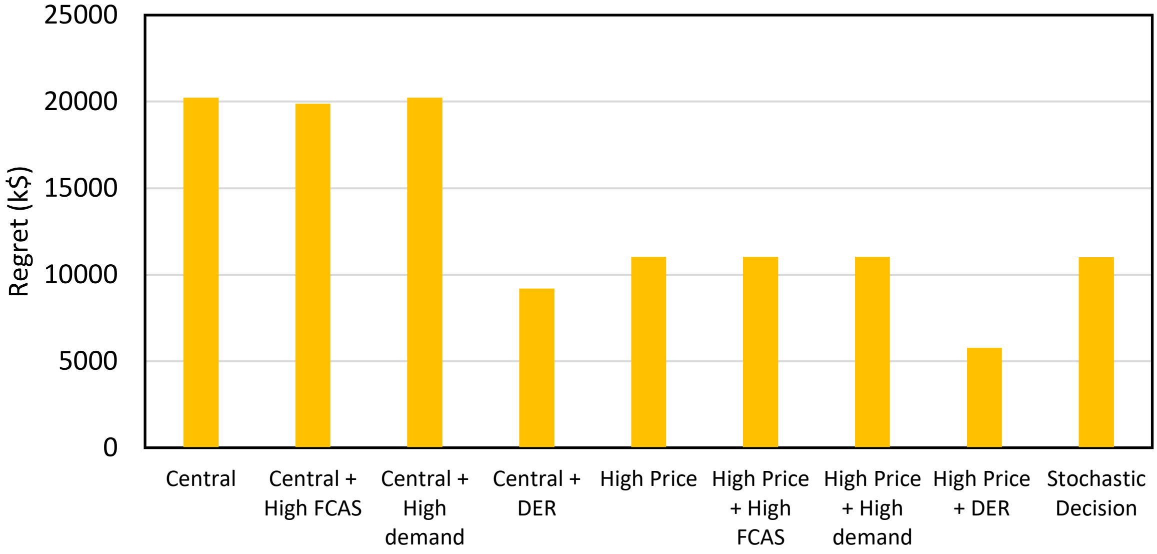


Figure 67. Regret analysis during a 2-week bushfire with fuel disruption for the investment decisions recommended in each case study including the impact of the EENS for Donald.

4.2 Microgrid Operation Case Studies

Previous results focused on the microgrid integrated investment and operation model, and the optimal investment decisions given different scenarios and assumptions. Once the optimal investment decision is known, the microgrid operational model can provide further detail on the microgrid operation, its resulting techno-economic performance during its lifetime, and provide a more accurate representation of the value the microgrid provides to the community.

The stochastic investment decisions for both Tarnagulla and Donald, presented in Section 4.1.1.3 and 4.1.2.3, respectively are selected to further analyse the microgrid operation under the high demand case study. During normal operation, higher demand will result in conditions where the microgrid can provide further value, as reducing the costs of purchasing energy from the wholesale market will be a main cost for the microgrid.

Additionally, the microgrid operation is studied under two significantly different scenarios, that represent worst and best-case scenarios, in terms of savings and revenues the microgrid can accrue.

- Business as usual (BAU) scenario: considers the Central wholesale market price scenario with lower prices and low volatility. Contingency FCAS prices are based on the Low price scenario. Network charges are applied directly to customers (aggregated at MV/LV transformers) and therefore, the microgrid DER cannot reduce the network charges in the microgrid. There are no additional value streams the microgrid can access during its normal operation.
- Additional value scenario: considers the High and Volatile wholesale market price scenario with also high contingency FCAS prices based on the High price scenario. It is assumed that the microgrid can access further value streams, facilitated by regulatory changes. First, network charges are applied to the community as a whole (at the point of connection of the microgrid with the upstream grid) using the HV customer network tariff as outlined by Powercor in its Pricing proposal for 2023/2024, presented in Table 13. In this case, the microgrid DER can be operated to reduce the network charges of the community as a whole, which would imply a further value stream. Additionally, during summer, microgrid DER resources can provide demand response (DR). DR price data available from other Victorian DNSP is used to select prices and duration of the required DR service [17]. Essentially, DR is modelled as a function of availability and delivery. Availability corresponds to a firm capacity DER provide, effectively limiting the DER output during a required period of time (in this case, during the summer months). DER receive a payment for the capacity they have available for DR, contractually agreeing to be able to increase their generation (or reduce its demand in case of batteries) equal to the available capacity when the DR service is called. Delivery corresponds to the actual times in which DR is required and the resources increase their energy output, effectively reducing the net demand of the community. DR delivery is assumed to take place at times of high wholesale market prices. The techno-economic details for DR service are included in Table 14

Table 13. NUoS for the microgrid charged at the point of connection of the microgrid with the upstream grid.

Network Tariff	Monthly peak demand ($/kVA/month)	Usage Peak (cents/kWh)	Usage off-Peak (cents/kWh)
Residential ToU	10.37	2.44	1.59

Table 14. Demand Response (DR) techno-economic details.

Network Tariff	DR Availability	DR Delivery
Price	$26,000/MW	$750/MWh
Duration	3 months	2 events per summer month and 90 minutes per event

Each year of the microgrid operation is defined by four design months that correspond to each season as detailed in Section 3.2.2. It is also assumed that the operation of two consecutive years is the same (Year 1 and Year 2, Year 3 and Year 4, etc.).

4.2.1 Microgrid Operational Results in Tarnagulla

The following results present the annual net cash flows (NCF) and the value stream breakdown during the lifetime of the microgrid located in Tarnagulla with the DER installed capacity recommended by the stochastic investment analysis:

- PV system: 487 kW
- Diesel generator: 908 kW
- Battery system: 185kW/145kWh

Figure 68 displays the annual costs (-) and revenues (+), as well as the annual NCF of the microgrid under the BAU scenario. Figure 69 displays the same information under the Additional value scenario. Savings are quantified by comparing the costs associated with the community without the microgrid DER in place to the costs when the microgrid DER are installed.

In both BAU and Additional value cases, annual NCF are positive, and wholesale market savings is the main benefit the microgrid DER provide to the community. In this sense, the results highlight that the microgrid can provide more value under high and volatile wholesale market prices, where the savings provided are in the order of ten times larger than in the central wholesale market price scenario. Overall, the positive NCF display that DER operation, with its associated costs, provides a net benefit to the community. FCAS revenues remain relatively low in both cases, as the battery is the most adequate resource to participate in this service, and the total battery installed capacity is relatively low. Additionally, the more detailed operational model of the MV network constraints allows to accurately capture the actual ability to provide FCAS, specially raise services, as lines and transformers need to be able to sustain the possible delivery of FCAS in case the service required.

In the Additional value scenario, it is assumed that further value streams can be accessed by the microgrid, to study their impact on microgrid operation and NCF. In particular it is considered the microgrid provides DR to the local DNSP, and the HV customer network tariff is charged at the interface between the microgrid and the upstream grid. In this way, microgrid DER operation can be optimized against these tariffs, accruing revenues quantified as savings when compared to the case without the microgrid in place, while providing valuable local services (peak demand reduction, energy imports at off-peak times). The technical performance of the microgrid is quantified in Table 15. These additional value streams are relatively low when compared to the wholesale market savings (they provide around 70-80 $k in annual revenues, accounting for an average of 10% of the NCF). However, when compared to the participation in markets like wholesale or FCAS, these revenues remain fairly constant through the horizon of the economic assessment and can be a more certain source of revenues for the microgrid, not depending on the ever-changing evolution of system-level markets. Additionally, as detailed in Table 15, these value streams send price signals to the microgrid DER to provide services to the system. In Table 15 the voltage management service provided by microgrid DER injecting and absorbing reactive power for the optimal microgrid operation has been accounted. However, this value stream has not been monetized due to the lack of information regarding the price attached to voltage management services.

Overall, the BAU and Additional value streams scenarios NCF throughout the horizon of the economic assessment could be considered as the lower and upper limit on benefits the microgrid could provide, considering the highly uncertain future local and system-level conditions.

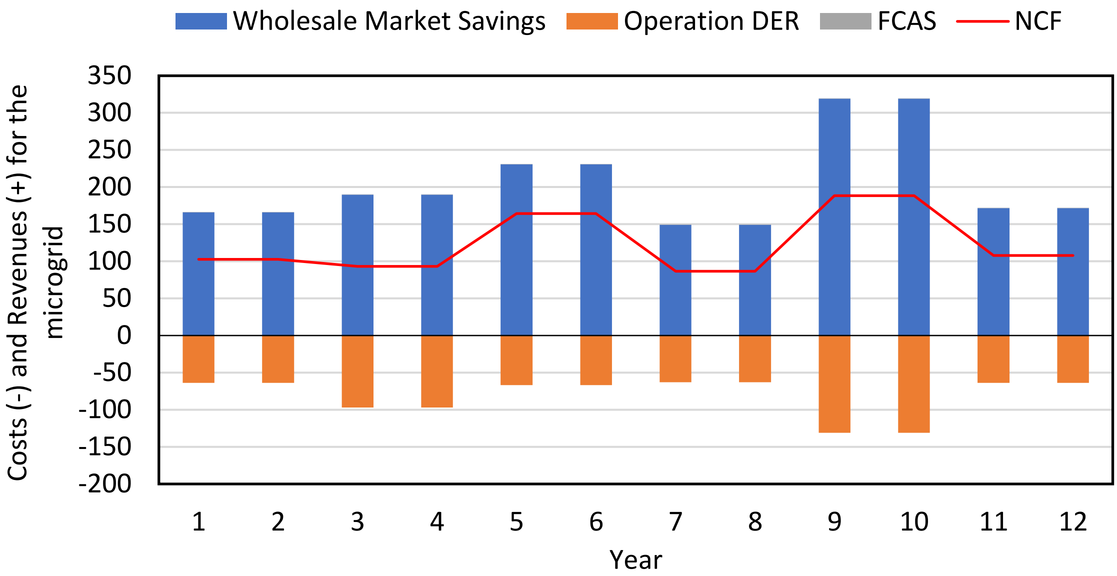


Figure 68. Annual value stream breakdown and net cash flows resulting from the microgrid operation in Tarnagulla during its lifetime under the BAU scenario. Savings are quantified by comparing the costs associated with the community without the microgrid DER in place to the costs when the microgrid DER are installed.

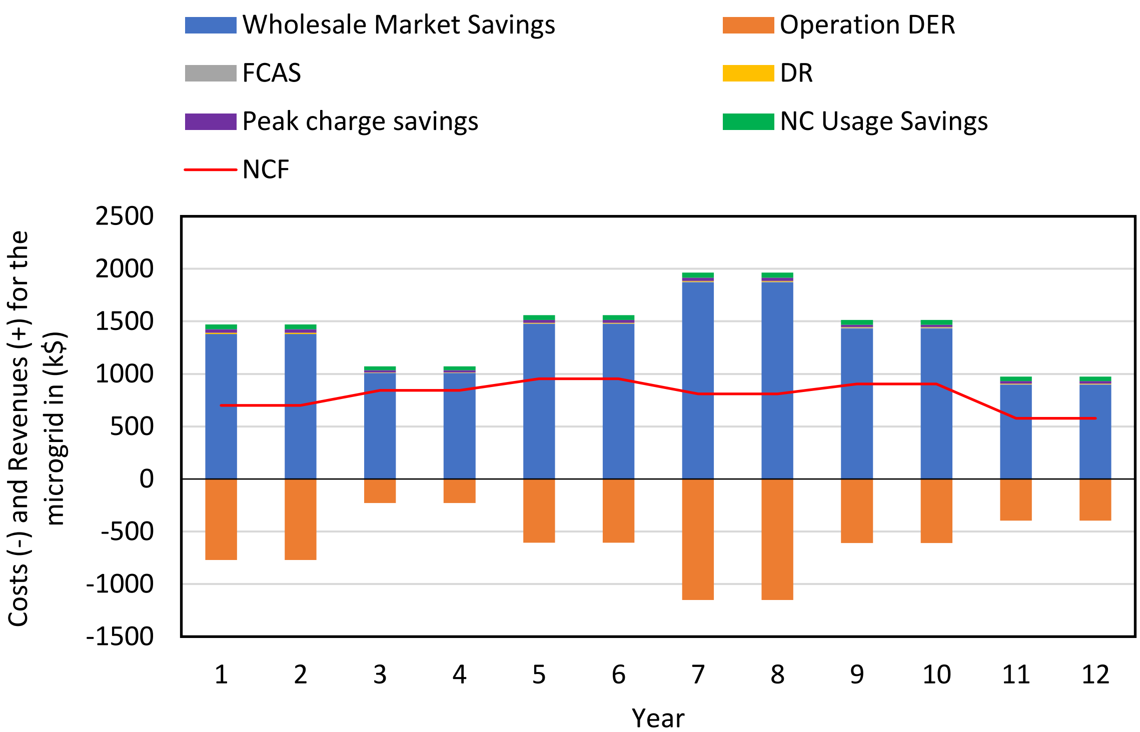


Figure 69. Annual value stream breakdown and net cash flows resulting from the microgrid operation in Tarnagulla during its lifetime under the Additional value scenario. Savings are quantified by comparing the costs associated with the community without the microgrid DER in place to the costs when the microgrid DER are installed.

Table 15. Technical benefits from additional value streams

Value stream	Performance	Relative Performance
Peak demand reduction	200 kW monthly average peak reduction	130 kW peak demand reduction/ 1MW microgrid DER
DR	48 kW average DR available during summer	31 kW DR/ 1 MW microgrid DER
Voltage management	24.34 MVArh average monthly reactive power support provided	16 MVArh/1 MW microgrid DER

4.2.2 Microgrid Operational Results in Donald

The following results present the annual net cash flows (NCF) and the value stream breakdown during the lifetime of the microgrid located in Donald with the DER installed capacity recommended by the stochastic investment analysis:

- PV system: 0 kW
- Diesel generator: 4156 kW
- Battery system: 3369kW/3369kWh

Figure 70 displays the annual costs (-) and revenues (+), as well as the annual NCF of the microgrid under the BAU scenario. Figure 71 displays the same information under the Additional value scenario. Savings are quantified by comparing the costs associated with the community without the microgrid DER in place to the costs when the microgrid DER are installed. Overall, in both scenarios, the microgrid operation in Donald, and the resulting economic performance is similar to the microgrid operation in Tarnagulla. The analysis on different value streams presented in Tarnagulla, is therefore applicable to Donald. However, it must be noted larger net cash flows in Donald, given that is a larger network that serves considerably more customers and that requires larger DER capacity installed, that in turn can accrue further revenues. The most relevant difference between Donald and Tarnagulla lies on the higher revenues coming from contingency FCAS in Donald. This is due to the larger installed capacity of battery systems in Donald, which among the available DER technologies are the most adequate resources to participate in contingency FCAS markets.

Like in the case of Tarnagulla, the BAU and Additional value streams scenarios NCF throughout the horizon of the economic assessment could be considered as the lower and upper limit on benefits the microgrid could accrue, respectively, considering the highly uncertain future local and system-level conditions.

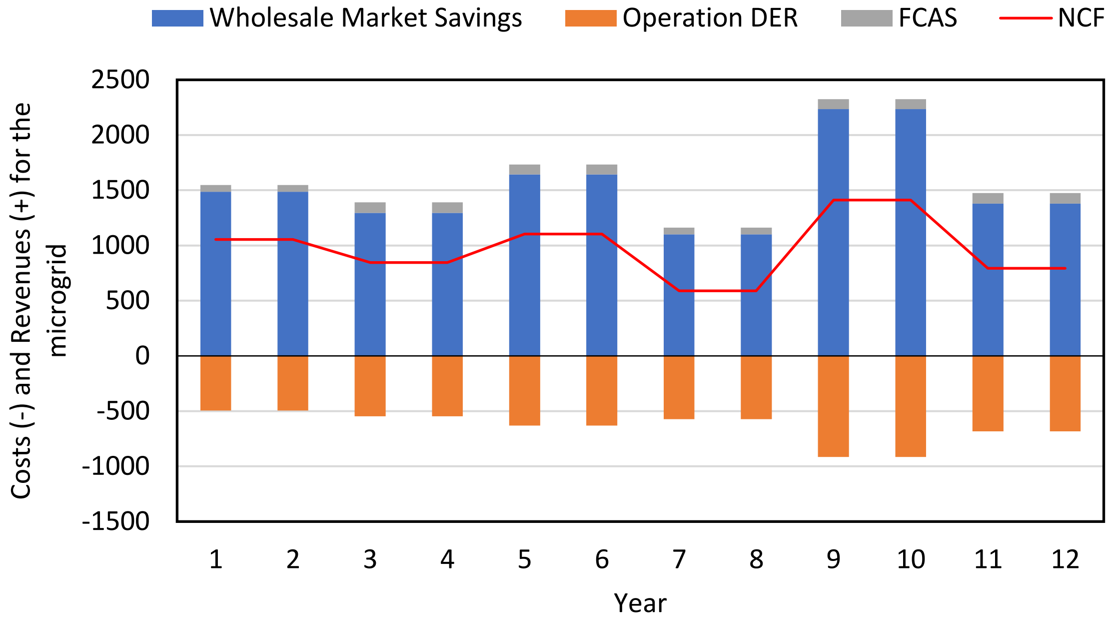


Figure 70. Annual value stream breakdown and net cash flows resulting from the microgrid operation in Donald during its lifetime under the BAU scenario. Savings are quantified by comparing the costs associated with the community without the microgrid DER in place to the costs when the microgrid DER are installed.

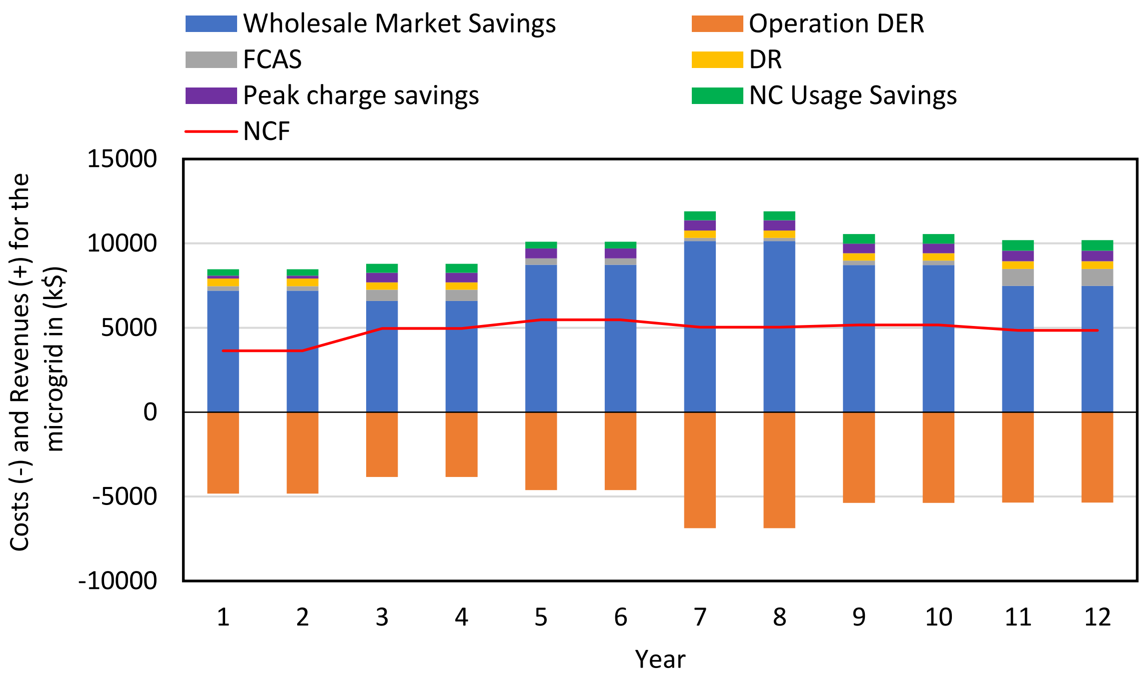


Figure 71. Annual value stream breakdown and net cash flows resulting from the microgrid operation in Donald during its lifetime under the Additional value scenario. Savings are

quantified by comparing the costs associated with the community without the microgrid DER in place to the costs when the microgrid DER are installed.

4.3 Net present value of the microgrids in Donald and Tarnagulla

The annual value stream breakdown and NCF are valuable tools to visualize the economic performance of the microgrid during its lifetime while understanding which value streams provide the most benefits for the microgrid during its normal operation. Net present value (NPV) analysis is used to calculate the current value of the future revenues and costs from the microgrid, considering both the investment costs, operational costs and revenues. NPV will be used to analyse the profitability of the microgrid project, considering the aggregate value the microgrid provides to the community as a whole.

To provide values that are as realistic as possible, maintenance and other annual operational costs from the DER are considered, based on the fixed OPEX (In $/MW of DER installed) presented in Table 6. Additionally, microgrid controller investment costs are included based on the average microgrid controller investment costs in the United States, which according to [4] are equal to AUD 224,000.

Figure 72 provides the NPV of the microgrid in both operational scenarios (i.e., BAU and Additional value streams) only considering normal operation of the microgrid i.e., without including the possible impact of bushfires. The results in Figure 72 display that in the BAU scenario, without the inclusion of the economic impact of bushfires, the microgrid is not a profitable project in the case of Tarnagulla, with a negative NPV estimated to -$500,000. In the additional value streams case, the microgrid presents a significantly higher NPV, even without the consideration of bushfires with NPV estimated as $5,000,000. As previously mentioned, the BAU and Additional Value Streams scenarios represent an estimate on lower and upper limit in terms on the expected value the microgrid project can provide in aggregate, highlighting the impact of uncertain system-level and local conditions. Overall, these results highlight which conditions lead to higher value achieved by the microgrid e.g., high and volatile wholesale market prices, high FCAS prices and monetizing additional value streams.

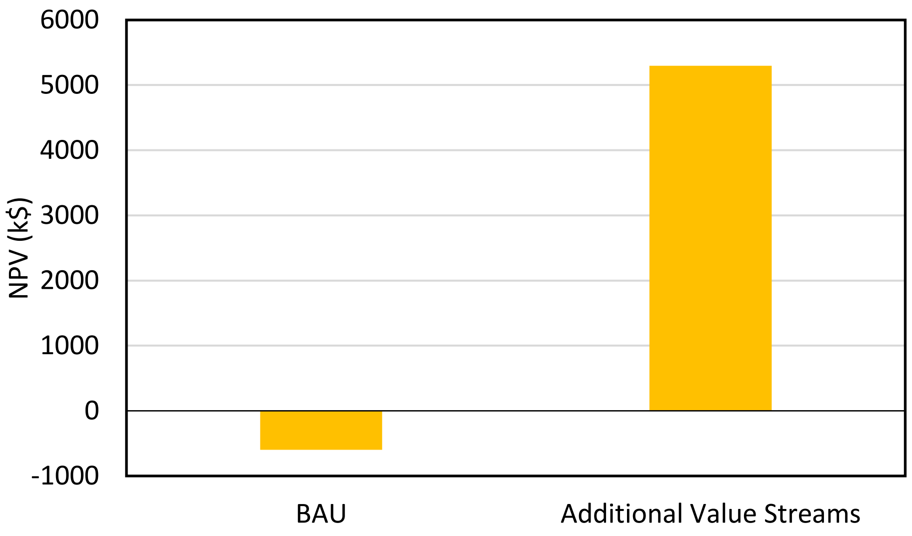


Figure 72. NPV analysis for the microgrid in Tarnagulla in the two operational case studies. The results only include the value provided during normal operation, without considering the additional value of reliability during extreme weather events.

Nevertheless, a key motivation for the microgrid project is its ability to reduce the impact of extreme weather events, in particular bushfires. While the microgrid integrated investment and operation model used the EENS calculated from Project 7, specific studies were carried out through the collaboration of University of Melbourne and Federation University in Project 8. In particular, Federation University developed a bushfire dynamic model, in which the different investment decisions presented in this report are studied in terms of their performance reducing EENS during a bushfire event. These results were used as well by the University of Melbourne, to validate the inclusion of the parametric studies from Project 7 were aligned with the latest more complete bushfire dynamic models developed in Project 8. Through this collaboration, the optimal stochastic investment for each town is introduced in Federation University's bushfire dynamics model to quantify the EENS for different disruption durations of the connection of each town with the upstream grid, the town being effectively islanded. Federation University and University of Melbourne performed an analysis of the EENS for the same disruption durations without the microgrid in place. This allows to understand the improvement in each town's reliability as a result of having the microgrid in place (Delta EENS). More details on the work developed by Federation University can be found in the report "Project 8: Economic and Risk Assessment – Part II". Finally, it must be noted that C4NET and Powercor established that an upper limit in credible disruption duration is six days. The results on the EENS in Tarnagulla with the microgrid in place and without the microgrid in place, and the resulting improvement in EENS (delta EENS) are presented in Figure 73.

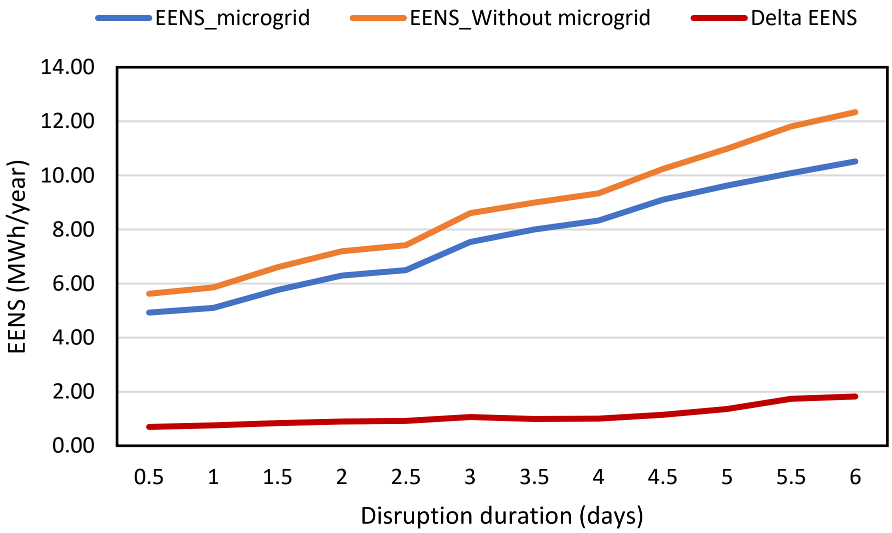


Figure 73. EENS (MWh/year) in Tarnagulla, with the microgrid in place (optimal stochastic investment), without the microgrid in place and the reduction of EENS achieved with the microgrid for different disruption durations

Figure 74 presents the resulting economic benefits from the increased network reliability when the Tarnagulla microgrid is in place for different disruption durations. The economic benefits are calculated using the increased network reliability, measured as the reduction of EENS (delta EENS in Figure 73) in MWh/year and the VCR which is assumed to be equal to $27.45/kWh. The expected economic benefits as the disruption duration increases are displayed in Figure 74. The general trend displayed in Figure 74 is that as the disruption duration increases, the reduction of EENS increases as well, and also the economic benefits related to the increased reliability. As EENS is a metric that includes uncertainty and probabilities surrounding failure rate of network components, the expected economic benefits are measured in k$/year. would be considered as an additional cash flow each year during the horizon of the economic assessment, considering different assumptions on how many days per year the town is disconnected from the upstream grid due to the impact of bushfires.

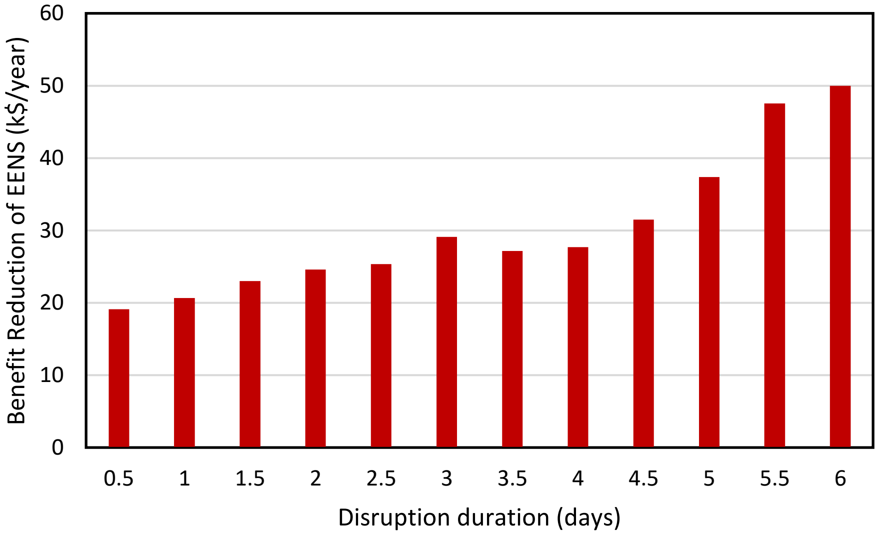


Figure 74. Annual economic benefits related to network reliability in Tarnagulla when having the microgrid in place considering the VCR equal to $27.45/kWh as the disruption duration increases

The results in Figure 75 detail the NPV evolution of the microgrid project in Tarnagulla for the BAU scenario as the number of days in which Tarnagulla is islanded due to extreme weather events increases. The NPV in Tarnagulla when not considering any disruption (0 days) is the same as the NPV presented in the BAU scenario in Figure 72. Then, the cashflows presented in Figure 74, as a result of the reduction of EENS, are applied to the twelve years of the horizon of the economic assessment. In this sense, the results of Figure 75 consider the cash flows from normal operation as well as increased network reliability considering different disruption durations. The results display that considering the benefits of network reliability is highly relevant when analysing the economic feasibility of the project. Even if NPV for the microgrid in Tarnagulla remains negative, NPV increases as the disruption duration increases. Overall, the results in Figure 75 provide a straightforward sensitivity to the value of the microgrid project as a function of the number of days per year in which Tarnagulla is expected to be islanded in the next 12 years.

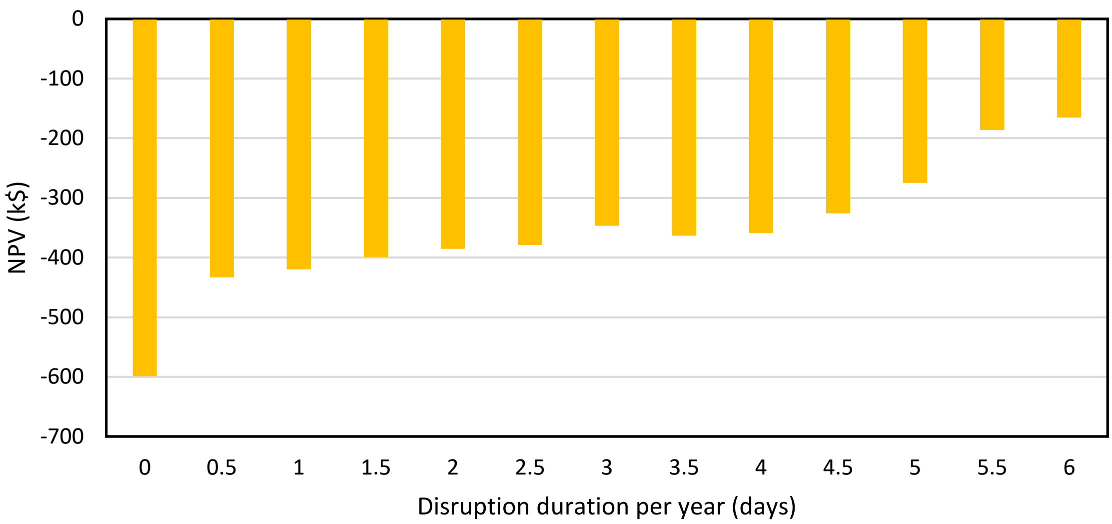


Figure 75. NPV sensitivity for the microgrid in Tarnagulla in the BAU scenario, with different number of days in which the microgrid is required to be islanded. The increased NPV corresponds to ENS cost reduction calculated comparing the ENS costs during the islanded event with and without the microgrid in place.

An equivalent NPV analysis for Donald is presented from Figure 76 to Figure 79. As in the case of Tarnagulla, the microgrid project in the BAU scenario without consideration of the impact of extreme weather events provides limited value, with marginally positive NPV shown in Figure 76. In the Additional Value Streams case there is significant value in the microgrid project. However, this case corresponds to a best case scenario in which high and volatile wholesale market prices, high contingency FCAS prices take place, as well as the microgrid being able to access further value streams. As discussed when the value stream breakdown was presented, the main value during normal operation comes from savings from the wholesale market, avoiding to purchase energy at times of price spikes, while also allowing to sell excess energy from the microgrid DER at these times. Since Donald is a larger community, with a larger energy demand, these savings are greater when compared to Tarnagulla, and thus the NPV is considerably larger when comparing both towns NPV in the Additional value streams scenario (NPV in Donald being over $30,000,000 in this case, whereas in Tarnagulla is $5,000,000). Like in the case of Tarnagulla, the NPV for BAU and Additional Value Streams scenario provides a lower and upper limit on the aggregate value the microgrid project can provide in Donald, considering the different uncertain system-level and local conditions in the future.

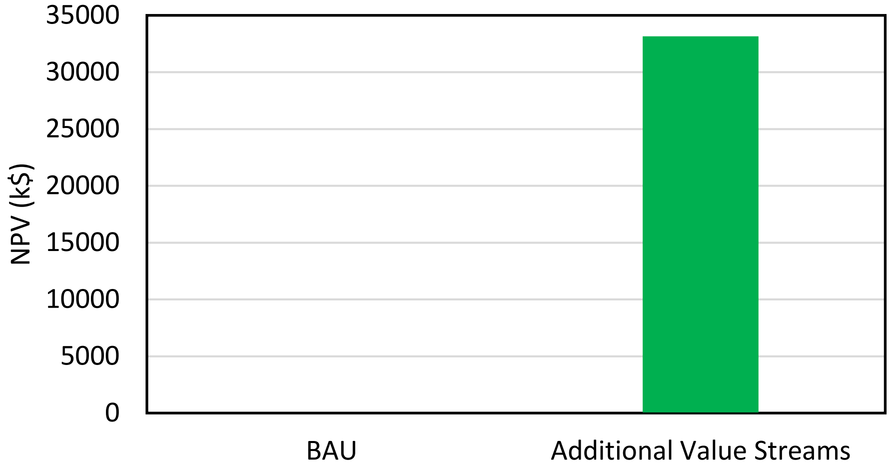


Figure 76 NPV analysis for the microgrid in Donald in the two operational case studies. The results only include the value provided during normal operation, without considering the additional value of reliability during extreme weather events.

The larger demand in Donald also results in higher costs if an extreme weather event takes place and the network is required to be islanded for a number of days (disruption duration). Like in the case of Tarnagulla, the EENS for the microgrid in Donald with the optimal stochastic investment recommended in this report was calculated for different disruption durations. This was then compared with the EENS without the microgrid in place to quantify the improvement in network reliability for different disruption durations in the connection of the town with the upstream grid (delta EENS). The results are presented in Figure 77, and highlight the increased order of magnitude of the EENS in Donald with respect to Tarnagulla (ten times higher), which also results in higher cash flows on the benefits of increased network reliability, presented in Figure 78.

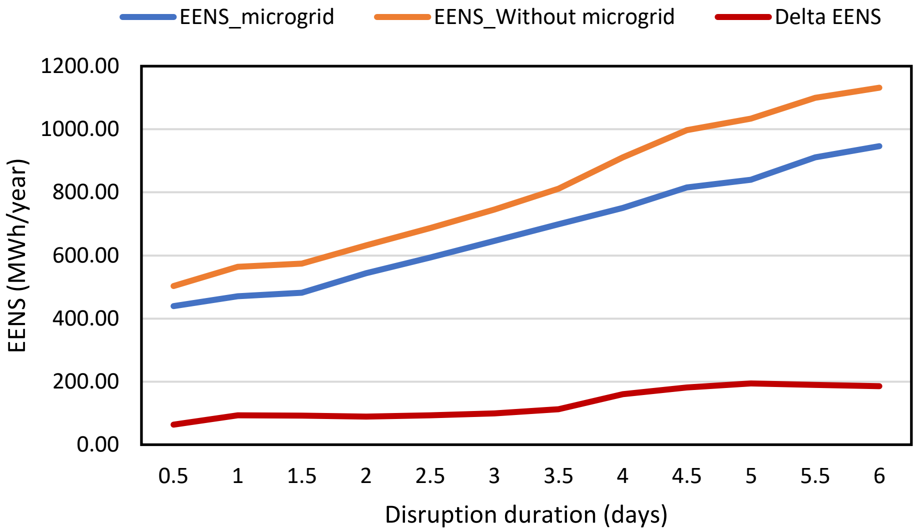


Figure 77. EENS (MWh/year) in Donald, with the microgrid in place (optimal stochastic investment), without the microgrid in place and the reduction of EENS achieved with the microgrid for different disruption durations

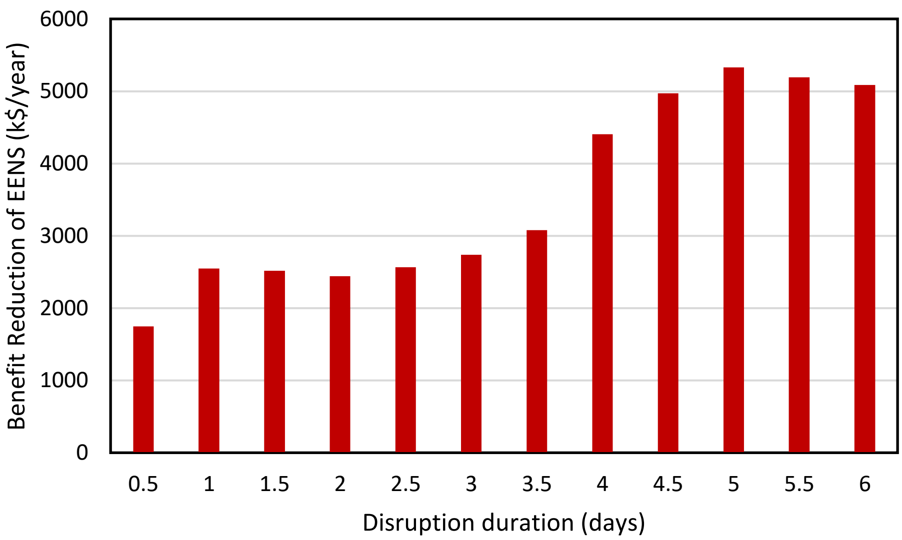


Figure 78. Annual economic benefits related to network reliability in Donald when having the microgrid in place considering the VCR equal to $27.45/kWh as the disruption duration increases

The results in Figure 79 detail the NPV evolution of the microgrid project in Donald for the BAU scenario as the number of days in which Donald is islanded due to extreme weather events increases. The NPV in Donald when not considering any disruption (0 days) is the same as the NPV presented in the BAU scenario in Figure 76. Then, the cashflows presented in Figure 78, as a result of the reduction of EENS, are applied to the twelve years of the economic assessment. In this sense, the results of Figure 79 consider the cash flows from normal operation as well as increased network reliability considering different disruption durations. The results display that considering the benefits of network reliability is a determining factor on the economic feasibility of the project. Given that Donald serves more customers, the results highlight that the impact the microgrid provides in terms of increased network reliability is significant, which also results in higher economic benefits, and more aggregate value provided by the project, even with short disruption durations. Overall, the results in Figure 75 provide a straightforward sensitivity to the value of the microgrid project as a function of the number of days per year in which Donald is expected to be islanded in the next 12 years.

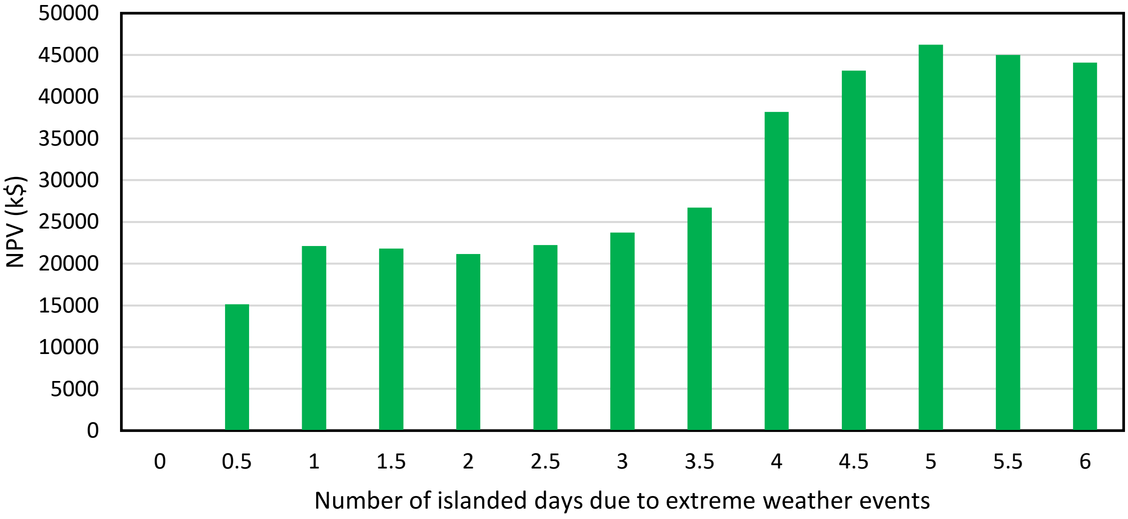


Figure 79. Average NPV sensitivity for the microgrid in Donald in the BAU scenario, with different number of days in which the microgrid is required to be islanded. The increased NPV corresponds to ENS cost reduction calculated comparing the ENS costs during the islanded event with and without the microgrid in place.

When analysing the microgrid operational results, Donald and Tarnagulla present significant differences on costs, revenues, NCF and NPV. Donald being a larger network that serves more customers requires further investment on DER, but also these DER can accrue more revenues and provide more savings to the community, especially when also considering the reduction of EENS during bushfires. In this context it is relevant to understand if these significantly larger cash flows and benefits in Donald are simply a result of the larger demand and DER size or if in a microgrid project, larger communities provide additional value (e.g., more diversity within the community, improved co-optimization of different value streams). To this end, in Figure 80 and Figure 81 the NPV of both Donald and Tarnagulla is normalized using each town's annual energy demand. The annual energy demand is calculated using the smart meter data from Project 7, equal to 1.30 GWh in Tarnagulla and 12.45 GWh in Donald. To include the impact of bushfires the design assumption considers 2 days disruption due to extreme weather events.

The results display that during the "normal operation" of the microgrid (i.e., not considering the impact of bushfires) the NPV of each town normalized with respect to their annual energy demand is not vastly different. In fact, in the Additional value scenario presented in Figure 81 the normalized NPV in Tarnagulla is higher. Therefore, the large differences in NCF and NPV between both communities can be partially explained by their size. This indicates that while a larger community might display higher value with greater NPV, the value delivered "per GWh demanded in the community" is comparable.

Considering the impact of bushfires that cause 2 days of disruption result in higher NPV per GWh of community demand. Before normalization this resulted in considerably higher NPV in Donald than Tarnagulla. Once the NPV is normalized with respect to the community demand, NPV per GWh of demand increases significantly in Donald for both the BAU scenario as well as the Additional Value Streams scenario. Thus, the results indicate larger communities might display further synergies with respect to the value microgrids can provide during normal operation and during extreme weather events.

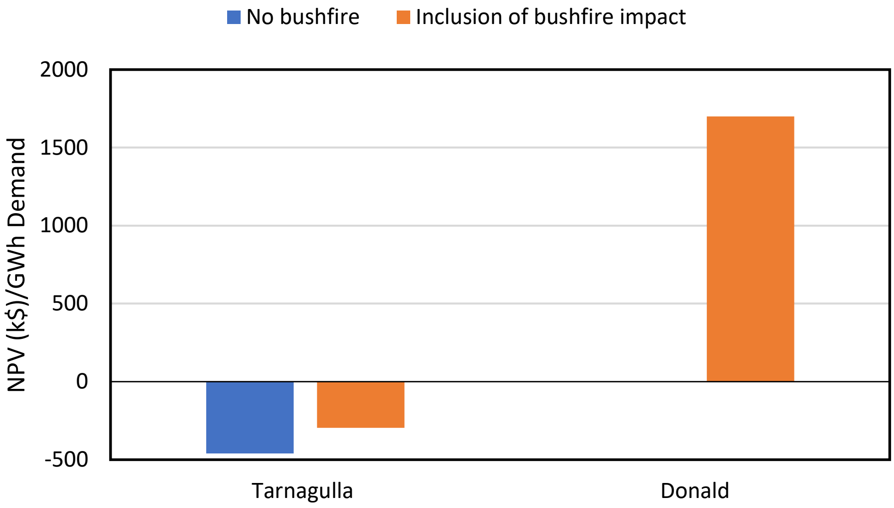


Figure 80. Comparison of NPV of the microgrids in Tarnagulla and Donald normalized with the annual demand of each community, considering the BAU scenario. The inclusion of bushfire impact assumes a two day disruption due to bushfires.

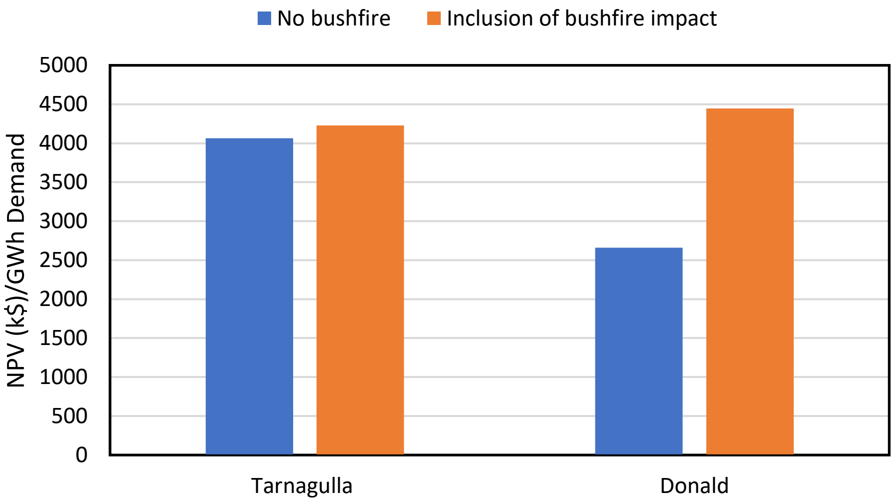


Figure 81. Comparison of NPV of the microgrids in Tarnagulla and Donald normalized with the annual demand of each community, considering the Additional value scenario. The inclusion of bushfire impact assumes a two day disruption due to bushfires.

4.4 Additional studies on microgrid operation

Microgrid operational results have been focused on analysing the value a microgrid in Tarnagulla and Donald can provide under different scenarios. The following studies are focused on specific details of the microgrid techno-economic performance, not covered in the general analysis.

4.4.1 Comparison of central and distributed DER in Tarnagulla

In the investment microgrid model, investment on DER was allowed at the PCC and at the LV side of the MV/LV transformers. This resulted on distributed investment decisions i.e., more than one DER of each specific technology was installed at different locations in the MV network.

However, in practice, installed DER at various locations in the MV network of each community might not be feasible. Additionally, further benefits that were not considered in this analysis might arise from installing a single resource of each technology. Namely, economies of scale, reduction of control costs, reduction on maintenance costs, etc.

Therefore, it is relevant to understand the techno-economic performance of distributed DER as opposed to central DER. This analysis is carried out for a year of microgrid operation in Tarnagulla, using the same total DER installed capacity as in the previous microgrid operational case studies:

- PV system: 487 kW
- Diesel generator: 908 kW
- Battery system: 185kW/145kWh

In the Central DER case, for each DER technology a single resource is installed in a specific location in the MV network. The location is informed by the most preferrable location information presented in Table 11. In the distributed DER case, more than one resource of each technology is installed, directly informed by the results of the microgrid integrated investment and operation model.

The value stream breakdown and NCF for each case (Central DER and Distributed DER) is presented in Figure 82. The results highlight that annual NCF do not differ significantly from Central DER and Distributed DER. Distributed DER are located at different points of the network and can supply the demand at different locations of the MV network with minimal losses. This results in further savings in purchasing energy from the wholesale market. Additionally, distributed DER better support the local network constraints, avoiding overloading of lines and managing voltages at different locations, in turn allowing further customer exports. When operated in a coordinated manner (amongst them and the customers) distributed DER can provide further value. However, central DER perform better on front-of-meter value streams. Notably in the central DER the revenues from FCAS participation and DR increase by 30%. This can be explained due to two factors. First, the larger central DER (specially batteries) have increased energy footroom and headroom to provide these services. Second, their provision of local services is limited when compared to the Distributed DER case. In the Central DER case as the resources can provide less local support to the network, given their location at a single point in the MV network, they have more available capacity to provide these services. However, overall central DER result in lower annual NCF than distributed DER operated in a coordinated manner. It must be noted, that given the difference between central and distributed DER is not significant, when considering other benefits arising from central DER not accounted for in this study (e.g., economies of scale, lower maintenance, operational and control costs) central DER might result more economically beneficial for the community.

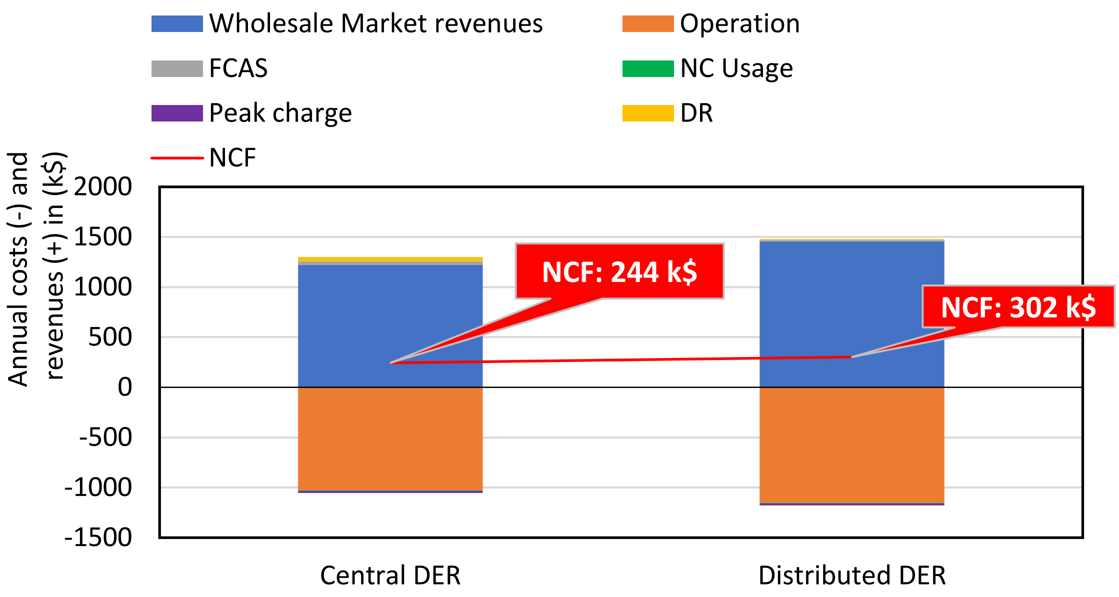


Figure 82. Comparison of the annual cash flows for two investment philosophies: central DER and distributed DER operated in a coordinated manner.

4.4.2 Network tariffs for microgrids

A key difference between the BAU and Additional value operational scenarios was the network tariff selected and at what level is charged. In the BAU scenario, network tariffs in the microgrid are assumed to follow the current convention. This entails network tariffs charged to each customer at the point of connection with the network. In this work since only the MV network is modelled, customers are aggregated at MV/LV transformer level and the residential ToU tariff is applied to the aggregation of the customer imports in each specific transformer. The microgrid DER are assumed to be connected front-of-the meter, and not behind-the meter of customers. Therefore, DER cannot provide any value to customers via network tariff arbitrage, reducing the network charges they are subject to. In contrast, in the Additional value scenario, it is assumed that a network tariff is applied for the aggregation of the microgrid at the interface of the microgrid with the upstream grid. This allows microgrid DER and the remaining resources in the network to be operated in a coordinate manner to reduce network charges. To this end, Powercor 22kV HV customer network tariff is used to charge the power imports and peak demand of the microgrid as whole. As discussed in 4.2.1, using a network tariff that charges the aggregated operation of the microgrid, does not only allow the microgrid to perceive savings from network charges, but also it incentivizes the microgrid to operate in a more cost-efficient manner in terms of network utilisation (e.g., reducing peak demand, importing power at favourable times).

However, when using the HV network tariff for the microgrid, the whole MV and LV network within the microgrid is not accounted for. That is, the network tariffs for LV customers consider the costs associated with the whole “supply chain” from transmission network to the LV network. On the other hand, a network tariff for a HV customer, connected at 22kV does not reflect the costs of the MV and LV networks within the community that need to be in place to deliver energy to the customers within the microgrid community.

Figure 83 presents the different lifetime network charges for the microgrid in Tarnagulla, under each network tariff structure. It is clear that the microgrid-level network tariff results in lower network charges, as not only the microgrid DER can operate to minimize these costs, but the prices in the HV network tariff are considerably lower, not reflecting the costs of the MV and LV network within the microgrid.

In microgrids, the concept of Local Use of Service (LUoS) is often referred as the network charges the members of the microgrid community are subject to. The combination of network tariffs charged at the interface of the microgrid (Microgrid-level) with the upstream grid and LUoS could be a future avenue that incentivizes cost-efficient use of the upstream network by microgrids (e.g, reducing peak demand and import energy at favourable times) while including the costs of the MV and LV network within the microgrid.

However, it is important that the customers within the microgrid are not subject to greater costs from network charges as a result of being part of a microgrid. By dividing the difference of microgrid network charges costs and the customer-level charges costs with respect to the total customer imports, the maximum LUoS flat rate price for customers can be calculated. This analysis assumes that the network charges at the microgrid-level would be shared by the customers in the microgrid, and it is looking at the total network charges paid by customers in both cases. Table 16 outlines this calculation and presents 5.26 cents/kWh as an order of magnitude of the maximum LUoS flat rate, which would result in customers within the microgrid being neutral in terms of network charges costs from the customer-level network tariffs to the Microgrid-level + LUoS network tariff.

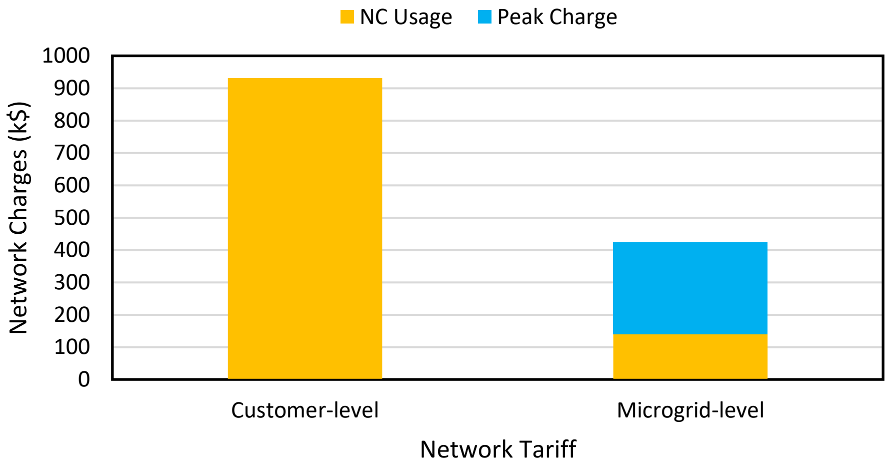


Figure 83. Comparison on Tarnagulla lifetime network charges when using network tariffs directly charging customer imports (residential ToU tariff) and network tariffs charging the aggregate operation of the microgrid at the interface between the microgrid and the upstream grid (HV customer tariff).

Table 16. Maximum LUoS Analysis in Tarnagulla

Network tariff terms	Customer-level	Microgrid-level
Total NC Usage (k$)	931.24	138.92
Total Peak charge (k$)	0.00	284.82
Total energy demanded (MWh)	9647.26	9647.26
Maximum LUoS (cents/kWh)	N/A	**5.26**

Total Charges in Community (k$)	931.24	931.24

4.4.2.1 *Economic Islanding*

Another important aspect of including network tariffs at the microgrid-level is that by accounting of all costs the microgrid is subject to by interacting with the upstream grid, economic islanding might take place. Economic islanding refers to a microgrid being economically incentivized to be operated in an islanded manner. By including a network tariff that charges peak demand and energy imports at the interface of the microgrid with the upstream grid, in addition to the costs of purchasing energy from the wholesale market, the optimal microgrid operation might result on effectively being islanded from the upstream grid and supply its local demand from the local DER generation. In the Donald operational results for the Additional value scenario, this behaviour is consistently seen during the fall and winter months. Figure 84 highlights this economic islanding behaviour by displaying for each distinct year in which the microgrid operation was modelled (e.g., two consecutive years operation was assumed to be equal) the differences in network charges between spring and summer and winter and fall months. From Figure 84 it can be inferred that in the years analysed during fall and winter the microgrid is not importing any energy from the grid, and thus it does not see any network charges with the microgrid-level network tariff, with the exception of Year 7.

In the case of Tarnagulla, optimal investment decisions do not allow the microgrid to be consistently operated in islanding manner, and the LUoS flat rate can be inferred in a straight forward manner. However, Donald displays distinct behaviours based on season, with economic islanding during fall and winter months. Therefore, other network tariff structures that can incentivize cost-efficient use of network while also acknowledging the economic islanding of the microgrid in different conditions need to be explored.

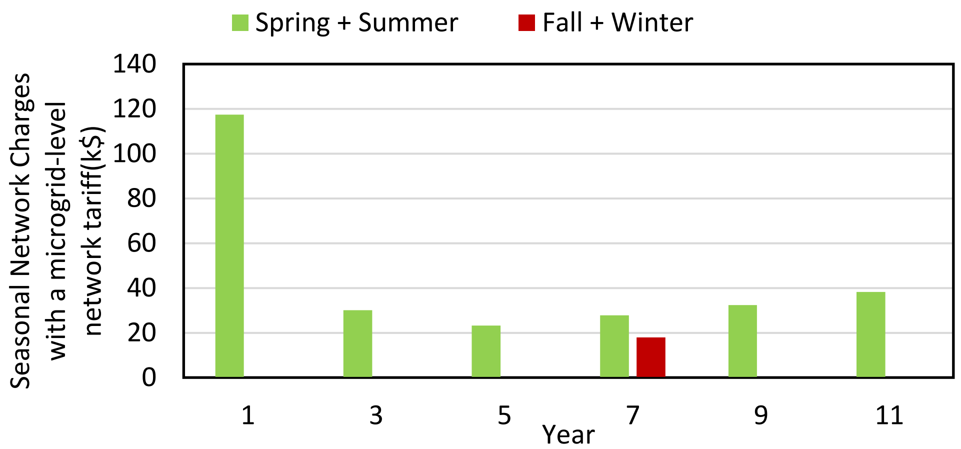


Figure 84. Seasonal network charges for Donald when the HV customer network tariff is applied at the interface of the microgrid with the upstream grid. Results are grouped by charges during spring and summer and charges in fall and winter

4.5 Key insights from the techno-economic framework

The techno-economic framework is comprised of a microgrid investment and operational model. With the microgrid integrated investment and operation model, the optimal investment decisions for a microgrid located in Donald and Tarnagulla have been explored under different scenarios. Additionally, the microgrid operational model has provided a detailed breakdown of the different value streams the microgrid can access during its lifetime, as well as estimates on the NPV of the microgrid project in both locations. The key insights from the analysis performed are the following:

- When not considering the impact of bushfires, required investment on PV systems is limited for both towns. However, as more severe bushfires occur with more frequency, investment on PV systems and battery systems are recommended to support the microgrid operation during the bushfire events given the parametric studies provided by Project 7.
- Wholesale market prices are the main uncertain parameter that drives the required microgrid investment, as savings arising from wholesale market arbitrage is the main source of revenues for the microgrid. In both Donald and Tarnagulla the microgrid integrated investment and operation model recommends relatively small diesel generators to withstand price spikes when wholesale markets are generally not high and volatile (e.g., central wholesale market scenario) and for high and volatile wholesale market prices the installed capacity of diesel generators significantly increases.
- Diesel generators are generally recommended as cost-efficient investment decisions that can be dispatched at times of price spikes in the wholesale market, providing significant benefits to the community. However, a community might not have a positive attitude towards diesel generators due to their environmental impact. When diesel generators were not considered as an investment option, investment in batteries significantly increased. While not considering diesel generators results in higher costs for the microgrid project it can come with additional benefits beyond environmental aspects. A key assumption around diesel generators is fuel cost (equal to $300/MWh) which was assumed to remain constant through the economic assessment horizon. This might not be the case, and the results displayed that higher fuel costs (around $400/MWh, higher or lower depending on the case study) make the final economic position of the microgrid not including diesel generators equal or more favourable than when diesel generators are included. Therefore, not investing in diesel generators might also be favourable avoiding an additional source of uncertainty which are fuel prices or future costs coming from regulatory developments to reduce carbon emissions.
- In most scenarios battery systems were recommended, as these are flexible resources that can provide an array of benefits to the microgrid. In Tarnagulla, 1 hour duration batteries are systematically selected, whereas in Donald we see batteries of 2 hour duration in the Central wholesale market price scenario and 1 hour duration in the High and Volatile wholesale market price scenario. It must be noted that the battery sizes recommended for Donald in the Central wholesale market price scenario are significantly larger when compared to the remaining cases. This might point out that larger batteries are more suited for longer durations, whereas smaller batteries (<4 MWh) are better suited for shorter durations in both microgrids.
- In Tarnagulla, the inclusion of bushfires using EENS has relevant impacts on the investment decision. However, in Donald it is not the case. Donald is a larger system that needs to supply further demand. The possible savings from purchasing energy from the wholesale market drives the investment decisions, and when considering the EENS costs, the selected resources effectively reduce the EENS costs to optimal levels, according to the parametric studies from Project 7.
- When dealing with uncertain future scenarios, stochastic decisions that intrinsically account for uncertainty provide valuable insights. Stochastic investment decisions provide the optimal decision to withstand uncertainty, and in this case provide robust solutions for different future wholesale market price scenarios., which are the main uncertainty source affecting microgrid investment decisions. Stochastic decisions displayed that if a credible future scenario consists of high and volatile wholesale market prices, the risks associated with purchasing energy to meet the microgrid local demand in this scenario drive the investment decision. However, in the event wholesale market prices followed a less volatile evolution, the costs and revenues arising from further investment on DER will still be acceptable.
- When designing a microgrid including the impact of bushfires using EENS, the probability associated with bushfires is a critical parameter. When design considers higher probabilities of bushfire occurrence, investment decisions significantly change from the design without considering the impact of bushfires. Additionally, the impact of assumptions such as PV efficiency during the bushfire, fuel disruption or presence of customer-owned DER will have a relevant impact on the optimal investment decisions.

- When designing a microgrid in a region where severe bushfires are likely to take place, directly including in the investment model credible bushfire events is a critical step to understand the required optimal investment during the event. Severe bushfires, like the two-week bushfire with one week fuel disruption included in the analysis, can yield to actual energy not served that entails unacceptable costs. This was highlighted in the regret analysis, were the investment decisions that considered the costs associated with EENS in the actual bushfire event resulted in high costs of energy not served, and thus high regrets associated with the investment decision.
- Regarding the microgrid operational results, wholesale market savings is the main source of revenues for the microgrid. The microgrid DER can supply a large share of the local demand, avoiding to purchase energy from the wholesale market, as well as providing wholesale market arbitrage and exporting power at times of high prices.
- Additional value streams can incentivize the microgrid DER to provide valuable services such as peak demand reduction, demand response, network tariff arbitrage or voltage management services. However, these value streams only comprise around 10% of the annual NCF and are not the main factor for the microgrid profitability. Nevertheless, as compared to system-level markets such as FCAS or wholesale market that have highly uncertain future evolutions, these additional value streams provide a consistent source of revenues for the microgrid during its lifetime.
- The NPV analysis considering both investment and operational cash flows displays that the microgrid project in Donald and Tarnagulla can provide value to the community and different stakeholders involved, especially when considering the economic impact of bushfires.
- Donald displays larger NCF and NPV compared to Tarnagulla. However, when normalizing the NPV with respect to the energy demand in each town the value the microgrid can provide with respect to "each GWh of energy demanded in the community" can be understood. This normalized NPV displays fewer striking differences between the two towns. However, when considering the impact of bushfires Donald provides considerable more value per "GWh of demand" than Tarnagulla due to the synergies between optimal investment decisions for "normal operation" and to reduce bushfire impact.
- The techno-economic performance of central DER and distributed DER operated in a coordinated manner result in similar annual NCF. While the distributed DER outperforms the central DER by 62 $k during a year, if additional costs of maintenance, control costs and benefits of economies of scale of central DER beyond the scope of this project are considered, central DER might result in a more adequate investment.
- Network tariffs charged at microgrid-level can incentivize the cost-efficient use of the network, yielding to savings while the microgrid provides different technical benefits (i.e., reduction of peak demand and importing energy at favourable times). However, by charging a network tariff at microgrid-level the costs of the network inside the microgrid are not accounted, also leading to significant reduction of recovered costs for the DNSP. In Tarnagulla, the microgrid requires the upstream grid to support its operation, displaying a consistent operation throughout seasons during its lifetime. This allowed to propose the use of microgrid-level tariff + LUoS as an avenue to facilitate the benefits from the cost-reflective microgrid-level network tariff, while also acknowledging the costs of the MV and LV networks within the microgrid. Given the microgrid operational model and the case study selected it was found that a 5.26 cents/kWh flat rate LUoS for customers within the Tarnagulla microgrid would result in equal network charges to the BAU case, where network charges are only applied at customer level. In this specific case study, this would be the maximum acceptable LUoS that would ensure customers are not subject to higher costs as a result of being part of a microgrid (assuming the microgrid-level network charges would also be paid by customers).
- In the case of Donald, by including the microgrid-level network tariff, we consistently perceive seasonal differences through its lifetime. During fall and winter months the microgrid in Donald is economically incentivized to operate islanded. These relevant seasonal differences comprise a more challenging case, where annual and lifetime average network charges cannot reflect the significantly different microgrid operation. Therefore, it is not adequate to propose a solution equivalent to Tarnagulla where consistent microgrid-level network charges allow to estimate adequate LUoS during its lifetime. Further analysis on possible regulatory frameworks for network tariffs suited for microgrids with significantly different operational behaviours within seasons should be carried out.

5 Business models for community microgrids: Commercial modelling Framework

5.1 Context

By definition, a business model defines the way through which value is created, captured, and delivered to the relevant stakeholders. How this value is delivered depends on the selected commercial model.

In the previous sections, a techno-economic analysis was conducted to extract as much value as technically achievable from microgrid operation, with the microgrid seen as an equivalent prosumer trading with external players as one entity. However, it is not only about modelling a purely technical and economic problem to establish microgrid's accessible value streams and quantify revenues and associated costs, but also crucial to define how this value is delivered and assess to what extent each actor/stakeholder throughout the value chain might benefit from microgrid operation. This comes from the fact that the value that could be captured was only available because of the centralized nature of the problem where the actions of each actor are coordinated to achieve a common objective.

In this respect, one of the key steps when defining a business model is to find key "partners", who may not be willing to "become a partner" and being part of the community microgrid unless its position is expected to improve/some benefits are guaranteed (or at least is no worse than "do nothing").

Therefore, the main question arising after demonstrating that the establishment of a microgrid is beneficial to the community as a "whole", is about the best strategy to allocate costs and benefits so as to set-up a win-win situation where microgrids become economically attractive for every actor involved in its operation. Indeed, some of the complex dynamics happening inside the microgrid "ecosystem" might be hidden by a "net" positive NPV (i.e., meaning that the project is economically viable) obtained by performing a cost benefit analysis on the aggregate of all stakeholders.

Deciding on the roles and responsibilities of each actor (e.g., who finances and owns the DER assets) can have a big impact on how a microgrid functions, such as accessible value streams, but also would affect the commercial feasibility of a microgrid project. Nonetheless, this is also dependent on the relevant regulatory framework that allows such interactions.

With this in mind, the commercial modelling framework consists of a value flow mapping model, to unveil and describe all the interactions and relevant economic transactions under different alternative allocation design solutions and an economic assessment model to measure their attractiveness and identify potential downsides from each actor's perspective.

5.2 Roles and responsibilities

The first step is to identify and define the roles to be played within the microgrid ecosystem who are then responsible of specific revenue and cost streams. In this way, it is possible to separate the "physical" actor from the potentially different roles it may be entitled to. The role-to-actor mapping is not a one-to-one correspondence as we will see in the following sections. In fact, a single actor can play multiple roles, for example in the case of retailer-owned microgrid DER, the retailer plays the role of DER assets owner but also the role of the retailer, fulfilling its mandate to provide energy to the end-customers; similarly, a single role can be played by multiple actors, for example in the case of mixed-ownership structure where multiple stakeholder financially contribute and hence own the DER assets. It should also be noted that the role-to-actor mapping is subject to the regulatory framework currently in place.

Hence, in this section, the main roles potentially present in the microgrid ecosystem are described along with their responsibilities.

- **Microgrid operator,** based on the collectively agreed upon objectives and principles by which the microgrid should be managed as a single entity, is responsible for controlling and orchestrating all flexible resources (e.g., microgrid DER and customers-owned resources) to maximize the benefits over the microgrid's lifetime while providing access to the different markets. A benefit sharing arrangement (e.g., as a **microgrid operation fee**) may be envisaged where the microgrid operator is allocated a share [x]% of the revenues accrued from microgrid's market participation to be compensated for the DER orchestration and market access services provision, potentially to be paid by the DER assets' owners (both customers-level and microgrid DER). This approach could incentivize microgrid operator to maximize the revenues. A fixed monthly payment [$Y/month] could also be taken into consideration to guarantee a level of “revenue certainty” for the relevant actor.

- **DER manufacturer** who manufactures and provides the DER assets with specific technical capabilities such as maximum charging and discharging rate and duration of the battery energy storage, and maximum and minimum power output of the diesel generator. The DER **capital expenditure** (and **maintenance costs**, when considered) represents an income for the actor playing such a role.
- **DER owner** who takes the responsibility for financing and therefore owning the microgrid DER assets, while also bearing the associated risks. The DER capital expenditure (and maintenance costs, when considered) represents one of the potential expenditures for the actor(s) playing such a role, along with other **costs associated with DER operation**, e.g., cost of fuel for diesel generator. As such, the DER owner may be entitled to accrue a great share of benefits to be able to recover the investment, including those from **wholesale energy market arbitrage** and **FCAS market** participation. However, the access and guarantee of a specific proportion of the resulting value streams is dependent on the ownership model, e.g., whether it is an equity share-based or lease-based ownership model, as it will be discussed in section 5.3. The role of a microgrid DER owner can be taken up by many actors, including an energy retailer, the end-customers, as well as any other third-party company. However, which solution suits best depends on many factors which will be explored in the following section.
- **Distribution network service provider (DNSP)** who owns and controls the distribution network. As such, it is responsible of delivering electricity to end-customers in a safe and reliable manner, upon the payment of Network Use of Service (NUoS) charge as a means to recover network assets’ investment costs. These charges, which represent an income for the DNSP, can be redeemed in the form of usage-dependent and/or peak demand dependent, and are passed down to the end-customer as part of their retail bill. It should be noted that, under the current regulatory setup, network charges are applicable to network users for imported energy only, and therefore only end-customers and BESS may be subject to them. Moreover, as the DNSP is responsible for the design of cost-reflective network tariffs, possibly taking into account location and time of network usage, different design alternatives may lead to overall reduced income from network charges, compared to the business-as-usual case. On the other hand, this situation may be counterbalanced by the additional benefits coming from a more efficient use of the existing distribution network as DERs (both microgrid-level and customer-owned DER) respond to the different price signals. Not only can this help reduce/postpone the need for new network infrastructure investments, hence resulting in economic benefit from **capex deferral,** but also lower the need to procure **local network services,** e.g., network demand response (DR), through contracts with other parties to guarantee the network to be operated within its statutory limits and ensure an acceptable reliability level. In relation to this, two separate ad-hoc roles could be created, namely a “**network support service buyer**” and a “**network support service contractor**”. With respect to reliability requirements, the Service Target Performance Incentive Scheme (STPIS) envisages financial rewards and penalties to DNSP where they exceed and fall below their reliability targets, respectively. This is to encourage distributors to enhance service reliability but only in the case where customers are willing to pay for such improvements. In particular, customers pay a financial reward to the DNSP for the improved reliability, whereas penalties are applied in the form of network charges reduction for customers. Where a microgrid is in place, any reliability improvements would be reflected on the DNSP but also on end-customers as well as DER owner, and, depending on the ownership structure, an ad-hoc commercial agreement would be required to establish the financial transactions among the involved roles.
- **Competitive market participant**, who is registered and licensed to participate in the different markets:
    - **Retailer** who represents the final link in the energy value chain, buying electricity from producers (either directly from generators or from the wholesale market) and reselling it to final end-customers, based on customers’ consumption profile forecasts. Its throughput-based utility model envisages a revenue stream coming from the mark-up added to energy sourcing costs, and therefore it depends on the amount of kWh sold to consumers. Under a microgrid setup, cheaper energy could be locally sourced, and retailers could design attractive retail products for end-customers to distribute the

savings from wholesale energy market purchase, for example in the form of discount on retail bill.

  - **Aggregator**, who is a market participant whose value proposition lies in pooling and orchestrating a portfolio of resources (e.g., flexible loads/DER) to sell flexibility in the energy markets, creates value by modifying the expected consumption/generation profiles and makes profits from price arbitrage. The role of an aggregator can be taken up by many actors, including an energy retailer as well as the prosumers themselves. The former option, where the same actor provides a supply contract with flexibility options, would avoid a conflict potentially arising between the two intermediaries. In fact, any request from the aggregator to modify the power setpoint (either consumption or generation) would result in an imbalance for the retailer. These deviations from the forecasts represent a risk inherent to the retailer's business. On the other hand, retailers may benefit from aggregation (i.e., aggregator's "customer") as they could use the flexibility offered by aggregators[1] for hedging forecasting errors or large deviations in renewable energy generation. In this respect, a commercial agreement between the retailer and aggregator may be beneficial.

- **End-customers**, who are characterized by specific energy requirements to be met by the retailer. End-customers might be equipped with their own DER, installed behind-the-meter, giving them the ability to reduce the import from the grid by prioritizing the usage of local generation to meet their energy demand as well as to export to the grid when the local production exceeds the customer's energy needs. End-customers may be contracted by a retailer for the energy supply and benefit from an ad-hoc designed retail tariff to take account of the savings from wholesale energy market purchase from sourcing cheaper local energy available within the microgrid. Additionally, they can also choose to pass the control of their DER to an aggregator to accrue additional benefits from flexibility provision, upon the agreement on the shares of DER capacity to be retained for customer's self-consumption and for flexibility provision. The transactions among end-customers, retailer and aggregator are conditional to the commercial model in place.
- **DER lessee** represents the counterparty of the DER owner (i.e., lessor) when (and if) a lease contract is established. As it will be discussed in the following sections, under this contract, the lessee hires from the lessor an asset for a specific amount of time and pays a specified rental/lease fee. The lessee can therefore temporarily use the assets (i.e., microgrid DER) and, depending on whether there is a capital or operating lease, the risks/costs and benefits are transferred to the lessee (along with the ownership at the end of the lease term) or stays with the lessor, respectively. An application example of this arrangement could be a commercial model where a third-party, for instance the retailer, purchases (and owns) the microgrid DER while leasing their capacity to end-customers who benefit from microgrid operation (e.g., in the form of retail tariff discount) upon the payment of a lease fee. In this case, end-customers might be entitled not only to benefit from the savings from a reduced total cost for energy import from the wholesale market, but also to retain a share of the revenues from the microgrid's participation in other markets, e.g., FCAS. The way these are passed down to customers is conditional to the type of contracts in place, which also depends on the required protection level towards community members from market volatility and other relevant risks.

[1] Assuming the two roles are played by different actors.

5.3 Ownership models

As emerged from the description of the different roles in the previous section, ownership comes with rights but also with responsibilities and which solution may suit best also depends on many factors. Deciding who owns the microgrid DER assets can have a big impact on how a microgrid functions, including the accessible value streams.
In fact, to identify which actor is best positioned to play the microgrid DER owner role, it is crucial to make sure that such ownership model would enable the microgrid to access the greatest level of benefits from all the potentially available value streams.

As highlighted in [18], some of the key determinants are:

- Access to information. If not directly available to the DER owner, microgrid partners should collaborate and share information on matters such as existing/expected network issues, which could better inform the DER owner on the most suitable location to install the DER[2] at the investment stage, as well as a market outlook, for instance in terms of market prices evolution and potential from customer-side DER asset base.
- Financial strength and risk appetite. The cost of capital of stakeholders like DNSPs is comparably lower than other actors like end-customers. Moreover, depending on the initial upfront capital requirement, a different risk attitude may be shown. Therefore, for the economic assessment, an actor-specific (and role-specific) discount rate may be required to reflect this characteristic.
- Access to markets and Alignment with regulatory framework. Great value can be extracted from microgrid's market participation. However, due to ring-fencing, not all the ownership models (i.e., DNSP-owned) guarantee the microgrid the access to the full spectrum of value streams as benefits from markets participation may not be available or may be achievable under specific conditions (e.g., by leasing DER capacity to different actor, such as the retailer, having market accessibility).
- Ownership structure. The question about ownership does not refer only to the specific actor who finances the microgrid DER investment, but also to the ownership structure which has an impact on how the DER owner's associated responsibilities and risks are handled.

These aspects will be further discussed in the following sections.

5.3.1 Ownership structure

A brief description of some potential ownership structures is provided below.

- **Full financial contribution:** This ownership structure envisages a single actor purchasing and owning the microgrid DER assets, while bearing all the risks but also retaining most of the benefits from microgrid operation, such as the revenues from markets participation or from network support service provision. Potential benefits re-allocation is conditional to contracts established with other community microgrid stakeholders.
- **Equity share**: Under this ownership setup, two or more stakeholders are financially responsible (and own) for a proportion of the microgrid DER assets and therefore share the risks associated with it. The cost and benefit which the shareholders are entitled to depend on the share they own. Then, each shareholder may propose a benefit re-allocation strategy with other community members.
- **Lease:** When a lease contract is established, a lessor (i.e., DER owner) hires a lessee an asset for a specific amount of time upon the payment of an agreed lease fee. Depending on how risks and responsibilities are handled, two types of leases can be identified, namely capital and operating lease. According to a capital lease contract, the renter is entitled to temporarily use the microgrid DER assets while obtaining full ownership at the end of the lease term. Therefore, risks and benefits are transferred to the lessee. On the other hand, under an operating lease contract, the renter is entitled to temporarily use and benefit from the assets (in accordance with the terms and conditions of the lease contract), but ownership and therefore risks remain with the lessor. The choice between capital and operating lease arrangements depends on the willingness of the lessor to transfer the risks coming from

[2] In this report, the term "end-customers" is used as synonym of "community members".

ownership transfer at the end of the lease term, and the inclination of the lessee to accept and deal with such risks.

5.3.2 Ownership model options

As discussed in the previous paragraph, identifying the most suitable actor(s) to take over the role of microgrid DER owner is a challenging task as many factors should be considered. In this section, some of the main ownership model options will be discussed, highlighting the pros and cons of each alternative.

5.3.2.1 Prosumer consortium

A prosumer consortium entails a single or multiple consumer(s) financing and owning the microgrid DER with the objective of maximizing the total profits (e.g., from markets participation, network support services provision) while meeting the electricity demand. In general, prosumers do not have the expertise to manage the assets and microgrid operation may be handled by a different stakeholder, e.g., aggregator or retailer, who orchestrates the DER and provides access to the different markets. As such, community members accrue all the revenues from markets participation, including FCAS market and wholesale energy arbitrage, benefiting from the reduced energy purchase from the grid by exploiting local generation. At the same time, community members sustain all associated costs, including investment and operating costs. The microgrid operator may be compensated by end-customers for the DER orchestration and access to markets services in the form of a share [%] of total revenues. The exact share to be allocated should be a value which is economically attractive for that specific actor to play the role of microgrid operator but at the same time it should guarantee that end-customers are able to recover the upfront investment in the microgrid DER and possibly result in a “net positive” position. Prosumers’ full financial contribution may be potentially facilitated by favourable interest rates on loans.

5.3.2.2 Third-party ownership

Under such ownership model, a third-party takes the responsibility for financing, owning and operating the energy assets. This solution would remove financial risk from the end-customers, also given the third party’s possibly greater financial strength. Such investors are likely to be familiar with how the different markets work, have access to information and can directly engage with end-customers. In fact, the third party may decide to transfer a share of accrued benefits to the community members to compensate them for making their behind-the-meter resources available for orchestration. In particular, if a retailer owns the microgrid DER, an ad-hoc retail tariff could be designed to transfer the savings from importing energy from the wholesale energy market down to end-customers (e.g., [y]% of these savings may be retained by the retailer while 1-[y]% been made available to community members). Alternatively, the retailer may decide to establish an operating lease contract with community members who, upon the payment of a lease fee (e.g., proportional to the total microgrid DER installed capacity or based on other metrics), also accrue the revenues associated with the leased share of DER (including revenues from FCAS market participation as well as from network service provision), as well as the (full) savings from wholesale energy import (e.g., in the form of credits in retail bill), while sustaining the operating costs.
On the other hand, the microgrid DER can potentially be owned by an aggregator, who has a different business model from a retailer’s one. In this case, if the aggregator is an independent actor from the retailer, a discounted retail tariff may not be directly applicable unless there is an agreement in place with the retailer. As the aggregator’s value proposition is to trade flexibility, end-customers can be compensated for their contribution to flexibility provision, e.g., by accruing a share of the revenues from FCAS market participation, while the retailer could retain part of the savings from importing energy from the wholesale market to be compensated for the deviations in the net import of the community (i.e., for the energy procured in the wholesale market based on forecasted consumption profiles and not used).

5.3.2.3 DNSP ownership

This ownership model envisages the DNSP investing in and owning the microgrid DER, intended to support network operation as an alternative to network investments, hence benefiting from delaying or even avoiding capital expenditure for new network infrastructure (CAPEX deferral).

While DNSPs have generally a lower cost of capital (i.e., are financially stronger than other actors) and have a significant amount of information about their own electricity network, some concerns may arise in terms of markets accessibility and alignment with the regulatory framework in place.

In fact, along with the provision of regulated electricity services, that is for example the installation/maintenance of poles and wires, DNSPs may also provide 'contestable' services[3]. However, the extent to which DNSPs can provide contestable services is governed by the ring-fencing[4] guideline established by the Australian Energy Regulator (AER), defining the obligations to which the DNSP is subject, to promote fair competition and avoid cross-subsidization[5]. As per ring-fencing objectives, DNSPs are generally prohibited from generating or retailing electricity. Such limitations may prevent the microgrid from accessing the full spectrum of value streams, such as benefits from markets participation.

In this respect, the DNSP my apply for a waiver of its obligation by including details such as the likely benefits of the grant of the waiver to electricity consumers [19].

For the microgrid to accrue the full value, the DNSP might own the microgrid DER and establish a lease contract with a third party who plays the role of microgrid operator and who is a fully licensed market participant (e.g., retailer, aggregator), for energy and FCAS market trading. By doing so, the DNSP could benefit from a lease payment/arrangement with the third-party intermediary[6] (potentially in the form of a share of that third party's revenues), with the lessee also sustaining the costs of operating the microgrid DER. Additionally, a bilateral agreement might be in place between the two parties for the provision of particular network services from microgrid DER.

While some barriers have been removed, allowing DNSPs to provide generation services to stand-alone power systems (SAPS) under a generation revenue cap mechanism[7] [20], there is no clarification thus far on limitations in the case of grid-connected microgrids and whether these extra revenues accrued under a lease-based agreement (in addition to those coming from network charges to end-customers) are subject to caps defined by the AER. In fact, the type of economic regulation that may apply to services provided by DSNPs depends on the electricity distribution service classification. Nonetheless, where the resources are providing multiple services, it is not easy to determine what proportion of DER capacity is used for network services and what for markets participation and determine the associated cash flows. Cross-subsidization risk exists, especially if the portion of the microgrid DER costs that are directly attributed to the provision of network services is added to the regulated asset base (RAB), to be then recovered from end-customers. This calls for a multi-function asset policy to regulate network assets that provide both regulated and unregulated services. In this respect, a "Multi-function asset guideline" was issued by the Economic Regulation Authority (ERA) after the amendments of the "Electricity Networks Access Code 2004", including a requirement, based on "net incremental revenue" concept, that "reduce regulated target revenue by a proportion of the revenue received for unregulated services that use regulated assets" [21]-[22].

With respect to the provision of network support services, when microgrid DER are not DNSP-owned, a commercial agreement must be in place between the two parties, i.e., the DNSP and the DER owner, where the DNSP agrees to pay for the provision of a particular network service. Moreover, DNSPs are allowed to use 'behind the meter' technologies to deliver network services, procured from

[3] Unregulated services offered on a competitive basis.

[4] It refers to the functional, accounting and legal separation of monopoly from contestable business activities (provided by DNSP or affiliated entity) where a regulated business also offers services into a competitive market.

[5] i.e., Costs relating to other services must not be allocated to distribution services. This obligation cannot be waived.

[6] Whom the DNSP must not have any relationship with under current ring-fencing rules.

[7] The amount of revenue DNSPs can earn from providing generation services is limited to up to a percentage of their annual revenue requirement.

third-parties or from their own ring-fenced affiliates rather than owning and controlling the assets.

5.3.2.4 Mixed ownership

A mixed-ownership model envisages two or more actors being financially responsible (and owning) for a share of the microgrid DER assets, thus sharing the risks associated with it. This multi-stakeholder option would decrease investments requirements from an individual actor. Under this approach, the costs and benefits arising from microgrid DER operation are shared among the shareholders, in proportion to their contribution to the capital expenditure. A combination of the abovementioned solutions can be implemented, for instance a co-ownership of end-customers and energy retailer.

5.3.3 Value streams and interactions with microgrid roles

Among the value streams of economic nature and financial transactions that can be accessed by and within the microgrid, the following have been considered for the economic assessment based on the outputs of the techno-economic analysis:

- **Wholesale energy market arbitrage**: this value stream refers to the ability of the microgrid to adjust the power exchange at the point of connection with the upstream grid in response to wholesale energy market price profile by exploiting the inherent flexibility of resources internal to the microgrid, i.e., microgrid DER and customer-owned DER. Given that the priority for the microgrid is to meet the customers' net demand, the amount of power purchase from the upstream grid depends on the available local generation. When local generation exceeds the energy needs of end-customers and, potentially, to charge the battery, the microgrid exports energy to the upstream grid. Therefore, we can distinguish two components in the **wholesale energy market arbitrage value stream**:
    - **Wholesale energy purchase savings,** that is a reduction of total costs associated with the power purchase from the upstream grid, enabled by the available local generation that is used to meet end-customers energy requirements and to charge the battery. This represents a benefit for the end-customers (with the retailer as intermediary). End-customers may allow for a share of such savings to be retained by the microgrid DER owner (or lessee in the case of lease-base agreement) to compensate them for making a "cheaper" energy source available. Thus, a corresponding "**Local generation purchase**" financial transaction can be introduced in the commercial model**.**
    - **Wholesale energy export revenues,** enabled by the available local generation, including microgrid DER) as well as customer-owned DER when behind-the-meter generation exceeds customers' demand. This value stream represents a benefit for both microgrid DER owner (or lessee in the case of lease-base agreement) and end-customers roles, in proportion to their contribution to the total exported energy.
- **Contingency FCAS market revenues**: this value stream refers to the revenues coming from contingency FCAS market participation. Both microgrid DER and customer-owned DER can contribute to the provision of this service, and the revenues are allocated [y]% to microgrid DER owner (or lessee in the case of lease-base agreement) and 1-[y]% to end-customers, depending on their agreed upon contribution.
- **Network support payment**: this value stream represents an expenditure for the actor playing the DNSP role for the procurement of network support service from the microgrid (e.g., peak demand reduction, voltage management), and an income for the resources owners who enabled such achievement. This payment is then to be allocated for [z]% to end-customers and 1-[z]% to microgrid DER owner (lessee if lease contract in place), with the allocation to be informed by the actual contribution of the different resources and conditional to the established commercial contract. This financial transaction would not exist if the DNSP is the microgrid DER owner.
- **Microgrid DER CAPEX:** it represents the cost sustained by the actor(s) playing the role of microgrid DER owner to purchase the microgrid DER assets, and it is therefore an income for DER manufacturer. In the case of mixed ownership model, the cost associated with the capital expenditure is to be allocated in proportion to each actor's contribution.

- **Microgrid DER OPEX:** this value stream refers to the cost sustained by the microgrid DER owner (or lessee if lease contract set up) to operate the DER. In the case of multi-stakeholders owning the assets, their contribution to the operational expenditure is proportional to the share of the assets they own.
- **Salvage value:** it refers to the value inherent to the assets at the end of the project lifetime (in the case of assets' lifetime being longer than the considered project's lifetime) as they could still be functional and potentially be resold. Therefore, this value stream would accrue as cash "inflow" to microgrid DER owner(s), proportionally to the share they own in the case of mixed ownership model, as the role sustaining the investment costs. In this specific project application, it is calculated using a straight-line depreciation of the asset and considering a scrap value of zero at the end of the asset's lifetime.
- **Network investment deferral:** with the microgrid in place being operated in a certain way, few network issues may be solved, hence avoiding or postponing the need for network infrastructure upgrade, and associated investment costs, required to guarantee the safe and reliable delivery of electricity to the end-customers. This would therefore be a benefit, or equivalent "income" for the DNSP. For this specific study, this value stream is considered equal to zero given that there is no planned network upgrade in the areas under analysis.
- **Network charges:** Network charges are the means through which the DNSP recovers the costs to build, operate and maintain the network infrastructure for its use by customers. Currently, network charges are applicable to imported energy only, and battery energy storage (BESS) is the only microgrid DER asset which is subject to them[8], along with "importing" end-customers. Nevertheless, an efficient use of the distribution network may be promoted via the design of more cost-reflective network tariffs, which can potentially lead to overall reduced network charges (or even revenues as seen from the microgrid DER owner(s) perspective), compared to the business-as-usual case, as DERs (both microgrid-level and customer-owned DER) would respond to the different price signals. Thus, depending on who these charges apply to, we can distinguish:
    - **Microgrid DER network charges,** which can be modelled as income for the DNSP and a cost for the microgrid DER owner(s) (or lessee depending on the set up commercial agreement) in proportion to their owned share in the case of mixed ownership model. When these costs are negative, it means that the microgrid DER owner is actually making profits from network tariff arbitrage.
    - **End-customers network charges** (measured at customer-level), evaluated as **savings** with respect to the business-as-usual condition, that is without the microgrid set up. It can be modelled as income for the end-customers and an equivalent expenditure for the DNSP that is collecting less money from less usage of the network infrastructure. Similarly, if these savings are negative, it means that the end-customers are paying more, thus resulting in additional revenues for the DNSP.
- **Microgrid operation service fee:** this financial transaction represents an income for the microgrid operator, paid evenly by all microgrid stakeholders, for the service of operating the DER (microgrid as well as customers-owned) and giving/managing access to the different markets and managing contracts (e.g., for network support services provision).
- **Energy retail bill savings:** energy retailer have direct contact with end-customers and may decide to transfer a share of benefits it may be entitled to the community members. This can be done in the form of a discounted ("fixed") retail tariff designed based on the expected savings from importing energy from the wholesale energy market or, alternatively, in the form of credits in retail bill which may depend on market conditions. If an agreement between the retailer and aggregator (if the two roles are played by two separate actors) is in place, benefits from end-customers contribution for FCAS market participation could also be included in their bill.
- **Retailer-aggregator settlement:** it represents the payment made by the aggregator to the retailer to be compensated for the deviations in the net import of the community, resulting from end-customers contribution to flexibility, and for which the retailer may have procured energy based on their expected net demand profile.
- **Microgrid DER lease fee:** this financial transaction represents the regular payment made by the microgrid DER lessee (I.e., expenditure) to the microgrid DER owner(s) (income) for the

[8] Unless DNSP-owned.

right of benefiting from their operation. The way this fee is defined depends on the commercial agreement between the two parties. For instance, it can be a varying amount and determined as a share of the total revenues accrued by DER lessee by operating its share of microgrid DER, or it can be prescribed as a fixed fee, e.g., calculated as an average of expected revenues over the project lifetime.

- **Network reliability benefits**: It can be modelled as a ”revenue” for the DNSP, as it would avoid penalties associated with reliability requirements, which end-customers benefit from upon the payment of certain fee. However, “monetize” this value stream is a challenging task. A point would be to consider the EENS with and without the microgrid set up as well as the corresponding extra capital expenditure, for which the investor should be compensated, associated with the microgrid DER resulting from the investment decision that includes reliability features.
- **Microgrid DER O&M**: it represents a fixed cost to be sustained by the microgrid DER owner(s) in proportion to their share in the case of mixed ownership or by the lessee when lease contract in place.
- **Grant revenues/funding**: this cash flow refers to any funding available to support the microgrid project implementation. This would most likely be used to cover (part of) microgrid DER CAPEX as it represents the lions’ share of total microgrid costs, and hence is to be accrued to microgrid DER owner (s) in proportion to their owned share in case of mixed ownership model. In these studies, funding is assumed equal to zero.

5.3.4 Commercial modelling framework

The commercial modelling framework consists of two sub-models, namely a value flow mapping model, where each value stream is assigned to the relevant “income” role(s) and “expenditure” role(s) and then mapped to the corresponding actors, and an economic assessment model to measure the economic attractiveness of each alternative allocation solution by generating specific cost benefit analysis (CBA) metrics for each actor.
In the next sections, the two sub-models are discussed in more detail.

5.3.4.1 Value flow mapping model

The value flow mapping model captures the incoming and outgoing financial flows of each microgrid role which are then mapped to the corresponding actor. The flow mapping is based on a topological description of the value and cash flow exchanges among actors, and it can be modelled through so-called *interaction matrices*, as discussed in [23]. A very high-level example of such interactions is depicted in Figure 85, displaying actors playing multiple roles, as well as roles played by multiple actors, along with the relevant value streams. The direction of each arrow defines the direction “from-to” of the cash flow associated with it.
The first step consists of quantifying the expected annual financial flows, evaluated through the optimized operation of the microgrid within the techno-economic framework, including those arising from the different commercial relationships in place. Both direct cash flows, such as revenues from markets participation, as well as indirect ones, included as savings with respect to the business-as-usual condition (i.e., without microgrid implemented), such as savings from wholesale energy purchase, are modelled.
The second step maps each cash flow to the relevant role as “Income” flow or “Expenditure” flow and this information is stored in the so-called **“cash flows-to-roles” interaction matrix**. By means of the cash flows-to-roles interaction matrix, it is then possible to evaluate each i^{th} role’s yearly net cash flow. Finally, each role is mapped to the relevant actor/s and this information is stored in the **roles-to-actors interaction matrix** which gives the flexibility to allocate different “shares” of roles and responsibilities to different actors, hence allowing for example for the modelling of mixed ownership models. All these yearly cash flows are evaluated for the project lifetime (T).

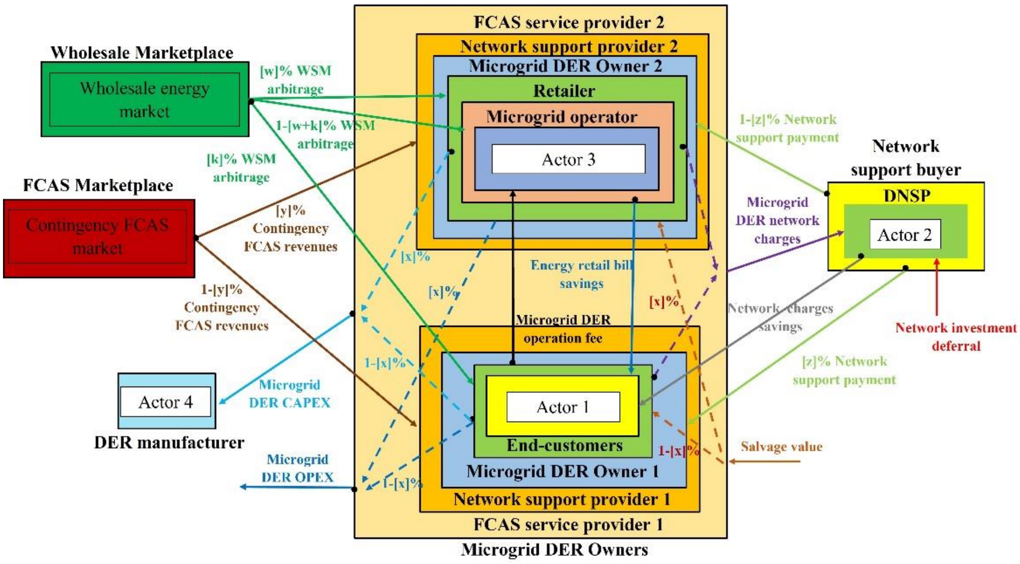


Figure 85. Example of value flow mapping for four different actors. The direction of each arrow defines the direction "from-to" of the value stream associated with it.

5.3.4.2 Economic Assessment Model and Options Evaluation

The economic assessment model generates the cost benefit analysis (CBA) metrics, which are then used to measure the attractiveness of different business model options from each actor's perspective. For every actor and every potential commercial model, it is possible to quantify how much value can be created (if any) by the microgrid's operation while accounting for all years into the future by performing a net present value (**NPV)**[9]analysis. A favourable/profitable outcome is expected from a positive NPV as value is created compared to the business-as-usual condition (i.e., without the microgrid set up), while under a negative NPV value condition the actor under analysis may not gain enough benefits to outweigh the expected costs. In this respect, when negative, an estimate of the minimum grant funding that may be required to reach marginal profitability, i.e., NPV=0, can be extracted as the absolute value of the NPV.

Based on the net present value metric, the i**nternal rate of return** criterion (IRR) can also be adopted. This technique compares the actor's minimum acceptable rate of return (i.e., the chosen discount rate) with the discount rate (i.e., IRR) for which marginal profitability, i.e., NPV=0, can be achieved. If the IRR is greater than the minimum required, then the participation of that specific actor to the microgrid project proves to be economically attractive[10].

The calculation of these metrics is based on the "time value of money" concept, and the i^{th} actor's net cash flow in year t is therefore "discounted" to the present. This comes from the fact that the value generated from the project may start materializing after some time in an *uncertain* future.

In this respect, the choice of the discount rate is a challenging task as it should consider the financial strength, cost of capital as well as the risk aversion of that specific actor under analysis. Therefore, not only should the discount rate be different for each actor, but also for the same actor a different risk attitude may be shown depending on the initial upfront capital requirement. For instance, the actor playing the role of "microgrid DER owner" is expected to sustain the major cost to enable microgrid's operation, that is the cost of purchasing the DER assets. This calls for different role-specific discount rates to be applied to reflect this characteristic, which is also affected by the way the initial investment is expected to be recovered, which is established within the commercial model. In fact, higher discount rates may be applicable for "risky" investment, whereas these may be reduced when the expected net

[9] Defined as the sum of the actor's discounted net cash flows over the project's lifetime.

[10] Alternative CBA metrics can also be deployed, such as the payback time (PBT) or the discounted payback time (DPBT), defined as the number of years required to recover the initial investment. The most favourable projects are those with a PBT/DPBT lower than the target (e.g., 10 years).

financial position is expected to be "safer". For example, in the case of retailer-owned (I.e., third-party ownership model) microgrid DER, the retailer could decide to transfer the expected savings from wholesale energy market purchase down to the end-customers in the form of a flat "discounted" retail tariff, designed by taking account of the expected benefit from the wholesale market (potentially applying a profit margin). Such commercial agreement would guarantee a fixed "income" (i.e., retail tariff savings) for the end-customers while the retailer bears all the risks associated with the uncertain evolution of the wholesale energy market prices.
On the other hand, the retailer may decide to apply a "real-time" type of retail tariff where end-customers are directly exposed to the wholesale market prices. In this case, all the risks associated with the uncertain wholesale energy market prices is entirely transferred to the end-customers. Therefore, looking at the "end-customers" actor, the discount rate applicable to the second scenario should be higher than the one used in the first scenario.
Finally, by coupling the value flow mapping approach and the CBA metrics, it is possible to assess the impact of microgrid operation under a specific commercial setup on every actor, potentially identifying the most influential interactions and a solution that could conveniently distribute as much value as possible to all stakeholders.
An illustrative example of the presented commercial modelling framework will be displayed in the following section.

5.4 Illustrative examples

5.4.1 Inputs and assumptions

In this section, an illustrative example of the presented commercial modelling framework will be presented. It should be noted that the aim is not to identify the best ownership and commercial models, but rather to study the impact on and the sensitivity of each actor to different value streams allocation strategies.
Additional input data required for the actors' cost-benefit analysis which are not provided by the techno-economic model as well as modelling assumptions are summarized below:

- Project lifetime assumed to be 12 years, equal to the minimum microgrid DER lifetime among the installed DER assets, namely the battery energy storage system.
- The value of the different cash flows is calculated through the techno-economic model under a high wholesale energy market and FCAS prices scenario.
- Network investment deferral is assumed equal to zero as there is no planned network upgrade in the areas under analysis.
- Additional costs such as transaction costs, metering equipment, AEMO market registration fees, taxes, inflation, contingencies and labour overhead, land lease, have not been included, although they can be incorporated in the model.
- Discount rates are different for each actor, and, for the same actor, a different discount rate may be applied depending on the "riskiness" of the specific role(s) played which is also impacted by the commercial model in place. Specifically, a deviation from the "default" discount rate, which is defined considering the actor's financial strength, is considered to model more or less risky commercial model setups. The "default" discount rate of the actors under analysis is reported in Table 17.
- No network support services (e.g., demand response) are procured and therefore the associated network support payment is assumed equal to zero.
- For simplicity, it is assumed that the probability of bushfires occurring during the microgrid lifetime is equal to zero.
- With respect to network charges, the savings accrued to end-customers are equal to zero as these charges are directly applied to customers' import/export at the MV/LV transformer level which is not affected by the operation of the microgrid DER.
- Moreover, microgrid DER are assumed to not be subject to network charges.

Given the points above, the value streams included in these illustrative examples are:

- Wholesale energy market arbitrage
- Contingency FCAS
- Microgrid DER CAPEX
- Microgrid DER OPEX
- Salvage value
- Microgrid operation service fee
- Retail bill savings
- Retailer-aggregator settlement
- Microgrid DER lease fee

And the following actors have been analyzed:

- Tarnagulla community
- Powercor, in the "DNSP" role
- "Third party", as a general term referring to a third-party involved in the microgrid (e.g., different retailers, independent aggregator, etc.), as specific project partners have not yet been identified.

Moreover, unless otherwise specified, it is assumed that the actor playing the role of retailer also has the "aggregator's" capabilities.

Table 17 Default discount rate for the different microgrid actors.

Actor	Value (%)
Citipower	5.4%
Third party/ies	8%
Tarnagulla community	12%

5.4.2 Case studies description

5.4.2.1 Case 1: Prosumer consortium

In this scenario, the Tarnagulla community owns the DER assets, both microgrid and customer-level, thus accruing all the revenues from wholesale energy and contingency FCAS markets' participation and sustaining the costs associated with OPEX as well as the investment costs. The revenues are assumed to accrue directly to end-customers rather than in the form of retail tariff discount. The operation of the microgrid is assumed to be handled by the actor referred here as "Third-party" who is assumed to also be playing the role of retailer as well as aggregator. As such, this actor is assumed to receive a variable payment from the community members as 1% of the total benefits, including markets' revenues, to be compensated for the DER orchestration and access to markets services as well as for the "lost" revenues as "retailer" for procuring less energy from the market. Moreover, since the retailer and aggregator roles are played by the same actor, the equivalent retailer-aggregator settlement payment is equal to zero.

Since community members are responsible for financing the microgrid DER, they are in a riskier position. Therefore, a higher discount rate compared to the "default" one is considered and assumed equal to 15%. For the actor playing the roles of microgrid operator, retailer and aggregator, the default discount rate is applied, i.e., 8%.

Under the current case study set up, and following the points provided in the previous section, Powercor does not experience any cash flows (net position equal to zero) and therefore the results associated with this actor are omitted.

The resulting cash flows, i.e., benefits (+) and costs (-), for the actors under analysis are reported in Figure 86 and Figure 87.

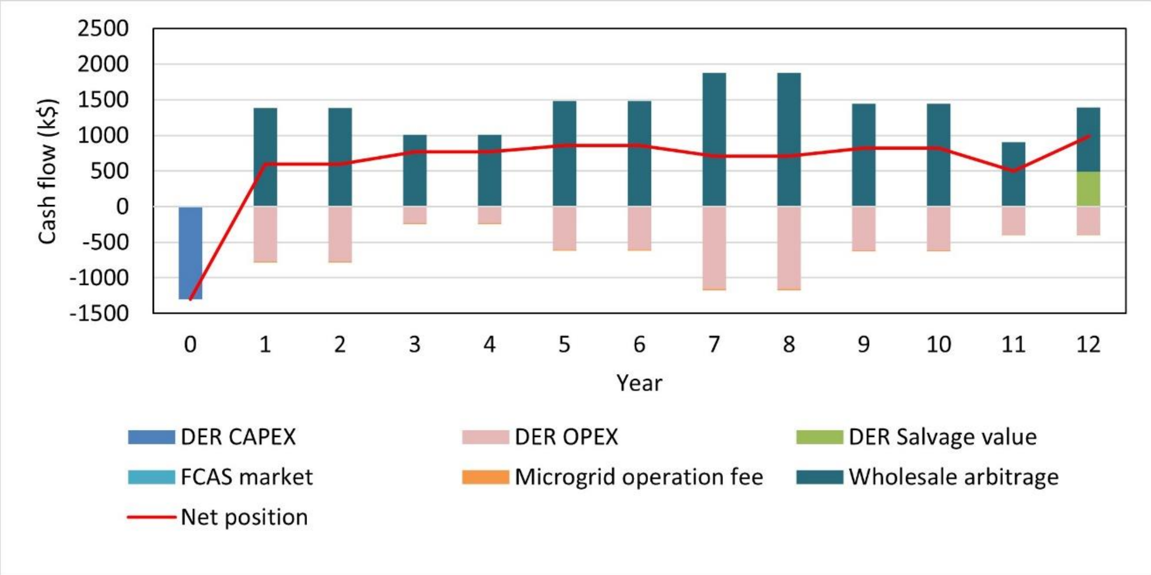


Figure 86. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Tarnagulla community" actor under a prosumer consortium model.

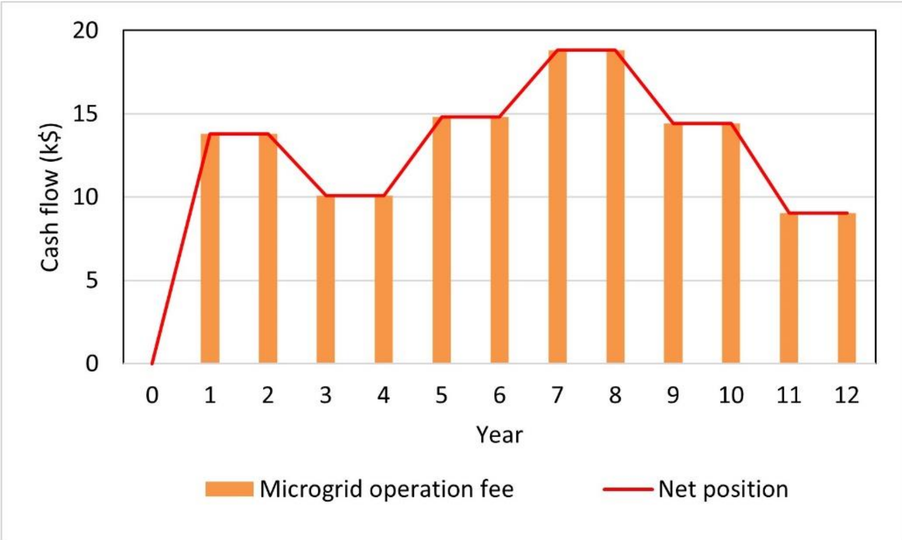


Figure 87. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Retailer" actor under a prosumer consortium model.

5.4.2.2 Case 2: Third party-owned

A. ***Retailer-owned***

Under this scenario, the "Third-party" actor plays the role of retailer as well as the aggregator while also being the owner of the microgrid DER and the operator of the microgrid. Therefore, it is assumed that all the revenues from wholesale energy and contingency FCAS markets' participation accrue directly to this actor, and also sustains the OPEX costs. For the service of operating the microgrid, community members pay a fixed microgrid operation service fee, assumed in this case equal to 0.5% of the average total benefits, considered lower than in case 1 as the microgrid operator is also the owner of the microgrid DER and already collects the greatest share of markets revenues. Again, under this scenario the retailer and aggregator roles are played by the same actor and therefore the equivalent retailer-aggregator settlement payment is equal to zero, and Powercor's net position is equal to zero. In this case, Tarnagulla community only plays the role of “end-customers” supplied by the retailer. Nevertheless, as a retailer, the “third-party” actor may decide to allocate part of the revenues from markets participation to the community who will then see a discount on their retail bill upon the payment of a fixed subscription fee, assumed in this case equal to 1% of the OPEX costs. Three different cases are analyzed, whose difference lies on the way the retail tariff is designed, which would then affect the way benefits are transferred to end-customer. More specifically:

- Case 2.A.1: benefits are transferred as a **fixed** yearly discount on the retail tariff, calculated as the 25% of the average expected revenues from wholesale and FCAS market participation, netted from DER OPEX.
- Case 2.A.2: this case considers 90% of the average expected revenues from wholesale market participation and 10% the average expected revenues from FCAS market over the microgrid lifetime discounted to the present. This is to account for “when” the benefits are expected to “materialize”, in accordance with the “time value” of money. Such benefit is passed down to end-customers as a **fixed** yearly discount on the retail tariff.

These two cases differ from each other on how much value the retailer may decide to transfer (and the strategy used to evaluate it) to end-customers. In both cases, the retailer chooses not to transfer the risk associated with market participation by guaranteeing end-customers with a fixed income every year. The resulting cash flows, i.e., benefits (+) and costs (-), for the actors under analysis are reported in Figure 88 and Figure 89 for case 2.A.1 and in Figure 90 and Figure 91 for case 2.A.2.
While the first two cases assume a fixed income for the end-customers with the retailer bearing the market’s risk, in the last case the end-customers are chosen to be more directly exposed (i.e., similar to real-time tariffs) to the wholesale market price fluctuations. More specifically:

- Case 2.A.3: benefits are directly transferred as **a variable** yearly discount on the retail tariff, calculated considering 30% of the revenues from wholesale market and 5% of the revenues from FCAS market participation netted by 5% of the operational expenditures for running the microgrid DER.

Given the different risk exposure of the Tarnagulla community actor, a lower discount rate, equal to 10%, is applied to evaluate the first two cases, whereas its default value is used for Case 2A.3. On the other hand, since the “preferred retailer” actor is the one responsible for financing the microgrid DER, to account for the greater risk exposure combined with the largest upfront capital requirement, a higher discount rate is considered and assumed equal to 10%.
The resulting cash flows, i.e., benefits (+) and costs (-), for the actors under analysis are reported in Figure 92 and Figure 93 for this latter case.

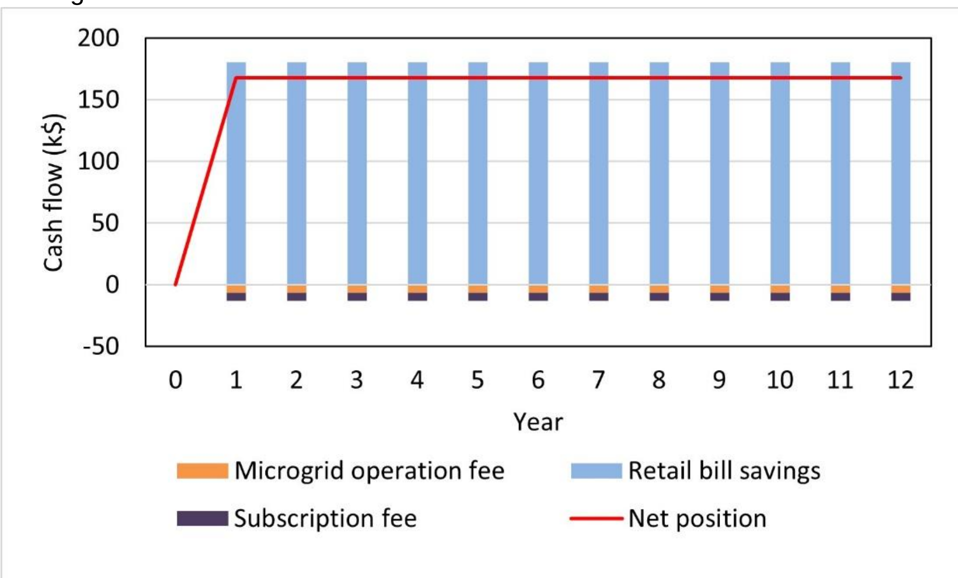


Figure 88. Resulting cash flows, i.e., benefits (+) and costs (-), for the “Tarnagulla community” actor under a third-party ownership model-2A.1.

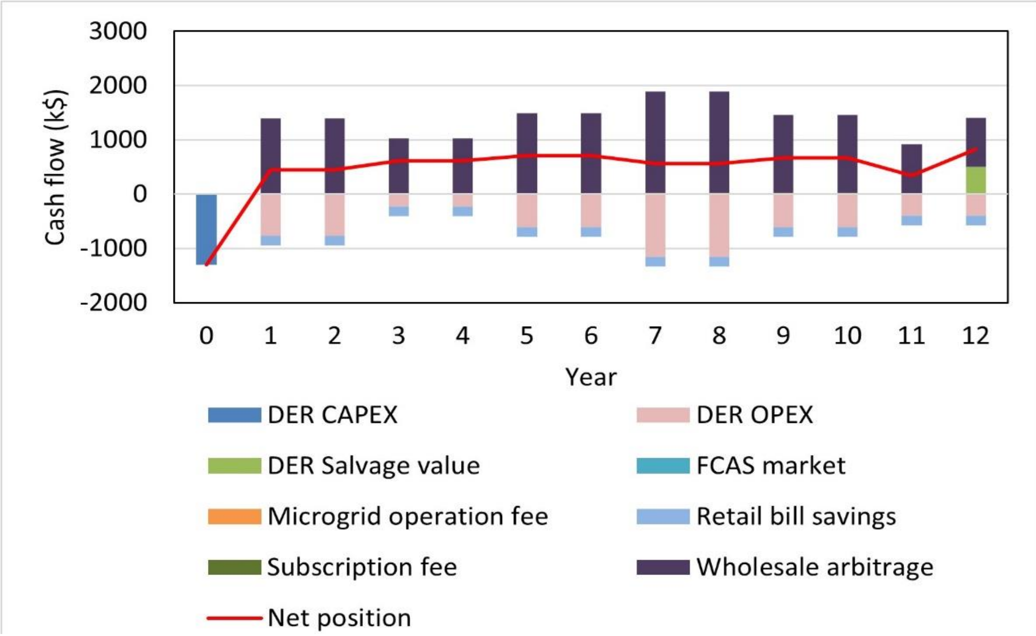


Figure 89. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Retailer" actor under a third-party ownership model-2A.1.

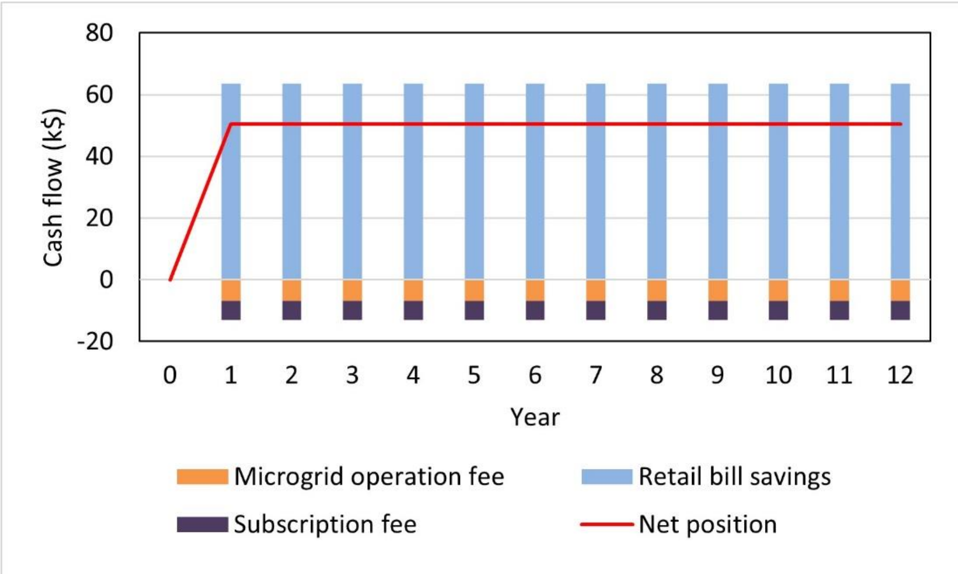


Figure 90. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Tarnagulla community" actor under a third-party ownership model-2A.2.

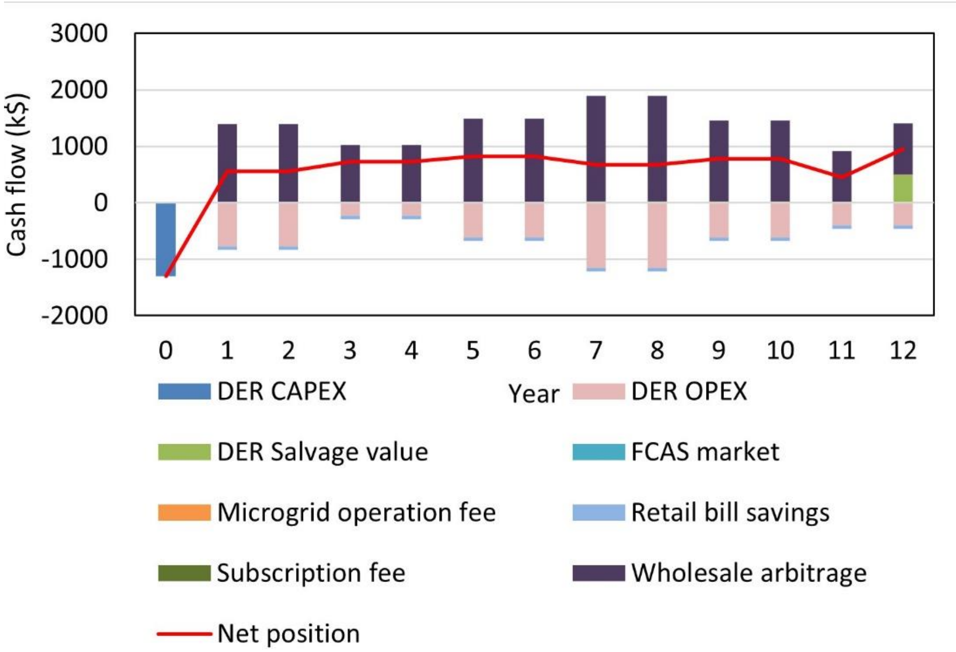


Figure 91. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Retailer" actor under a third-party ownership model-2A.2.

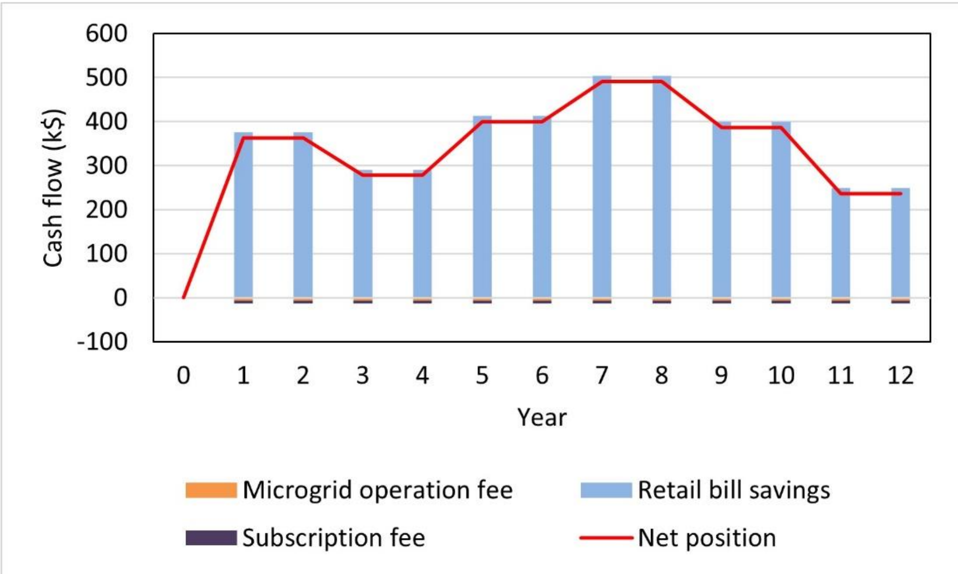


Figure 92. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Tarnagulla community" actor under a third-party ownership model-2A.3.

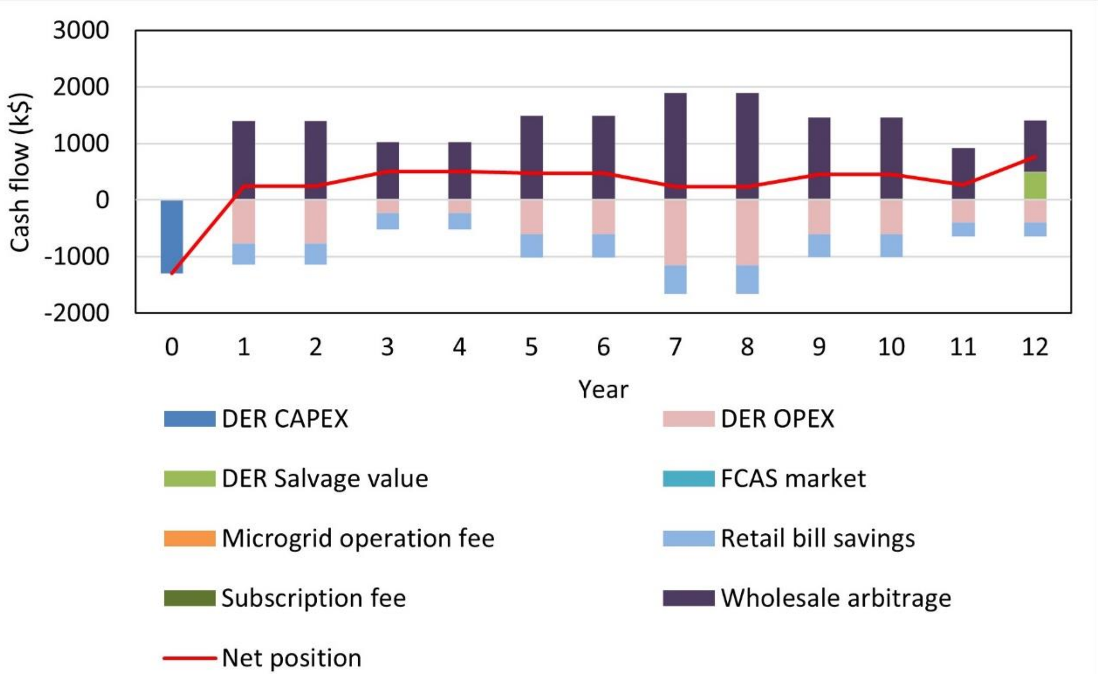


Figure 93. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Retailer" actor under a third-party ownership model-2A.3.

B. *Independent aggregator-owned*

Under this scenario, the actor who plays the role of retailer does not coincide with the one acting as aggregator. For the sake of simplicity, in this section we refer directly to "Retailer" as the actor playing the role of retailer and to "Aggregator" as the actor playing the role of the independent aggregator and operator of the microgrid, who also happens to be the owner of the microgrid DER under the current set up. Therefore, it is assumed that all the revenues from wholesale energy and contingency FCAS markets' participation accrue directly to the aggregator who also sustains the OPEX costs.

In this case, since retailer and aggregator actors do not coincide, it is assumed that there is a contract between the two parties which envisages a settlement payment made by the aggregator to the retailer to compensate for any potential imbalance with respect to the expected net demand profile, resulting from the DER orchestration, upon which the retailer may have procured the energy for its end-customers.

Two cases have been studied, based on the end-customers-retailer-aggregator interactions:

- Case 2.B.1: the retailer-aggregator settlement payment is assumed to be equal to 20% of the total markets' revenues. In this case, the retailer chooses not to transfer the risk to the end-customers, and it is assumed to design an ad-hoc retail tariff such that end-customers are guaranteed a fixed yearly saving on their retail tariff calculated as the 30% of the average retailer's expected net profit from its share of total markets revenues, over the microgrid's lifetime. This retail bill discount can be unlocked by end-customers upon the payment of a yearly subscription fee, assumed equal to 10% of the expected retail bill savings.
- Case 2.B.2: Compared to the previous case, this commercial set up sees the risk being transferred to end-customers who would not directly see a discount on their retail tariff, but rather some credits applied to their retail bill, paid by the aggregator and assumed equal to 10% of its net benefits[11],[12]. In this respect, the link is directly between the aggregator and the end-customers, and no subscription fee is therefore paid to the retailer. Since the risk allocated to the retailer is lower compared to case 2.B.1, the retailer-aggregator settlement payment is assumed to be equal to 10% of the total markets' revenues.

[11] It is assumed that for years when operating costs exceed the total revenues, no cost is transferred to the end-customers who would therefore receive zero credits.

[12] Assuming that this is allowed by an agreement between the retailer and the aggregator.

For the service of microgrid operation, the aggregator also receives from community members a microgrid operation service fee, assumed in this case equal to 3% and 2% of the total markets' revenues for case 2.B.1 and 2.B.2, respectively.

The resulting cash flows, i.e., benefits (+) and costs (-), for the actors under analysis are reported in Figure 94, Figure 95 and Figure 96 for case 2.B.1, and in Figure 97, Figure 98 and Figure 99 for case 2.B.2.

For the cost-benefit analysis, a 10% discount rate is applied to the aggregator actor (i.e., higher than default to account for the major expenditure responsible of) as well as for the retailer (higher than its default value) and end-customers (lower than its default value) in case 2B.1, whereas their default value is applied in case 2B.2.

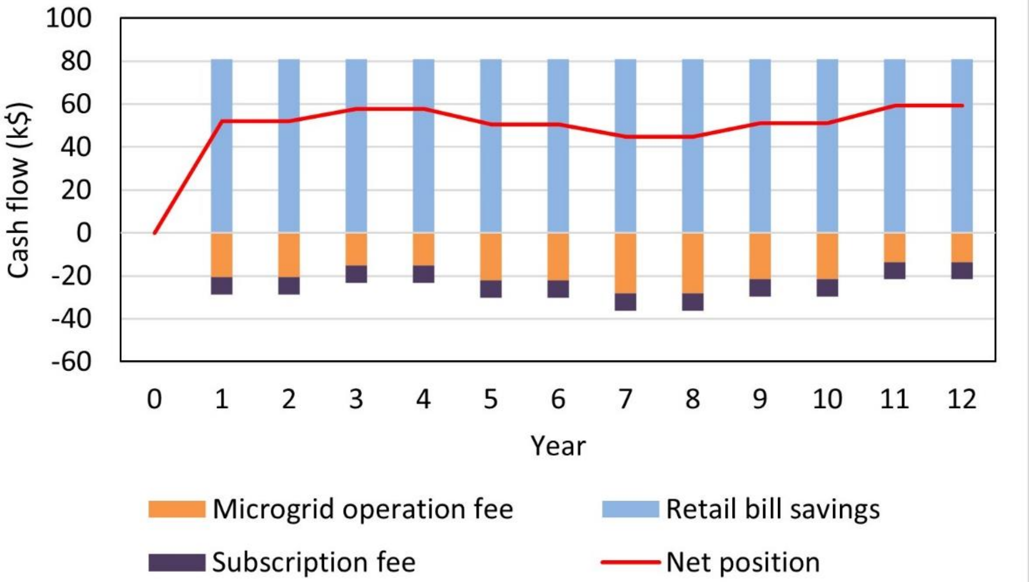


Figure 94. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Tarnagulla community" actor under a third-party ownership model-2B.1.

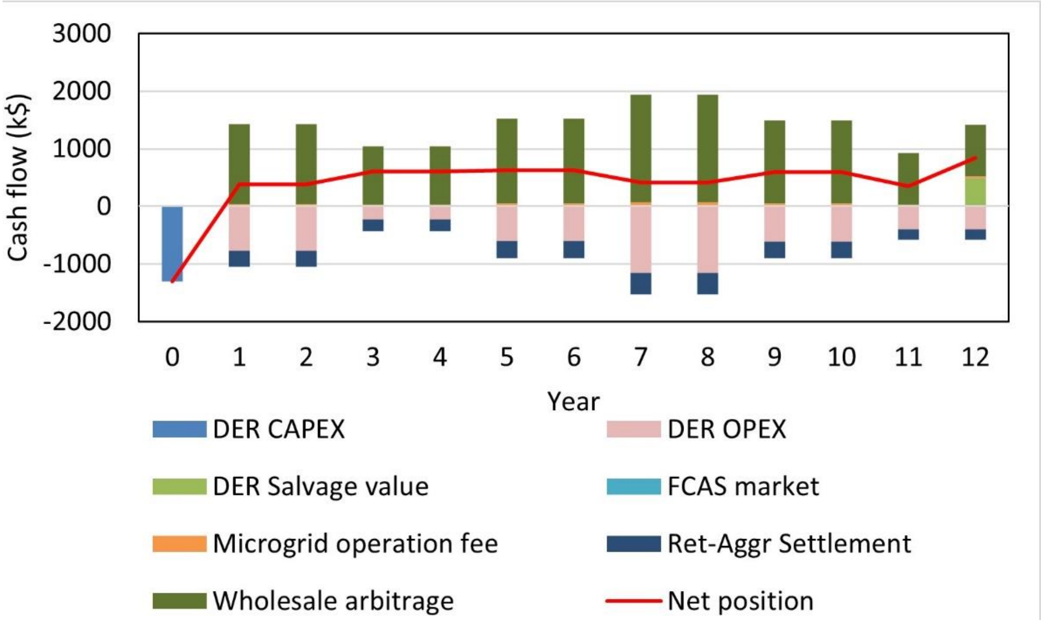


Figure 95. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Independent aggregator" actor under a third-party ownership model-2B.1.

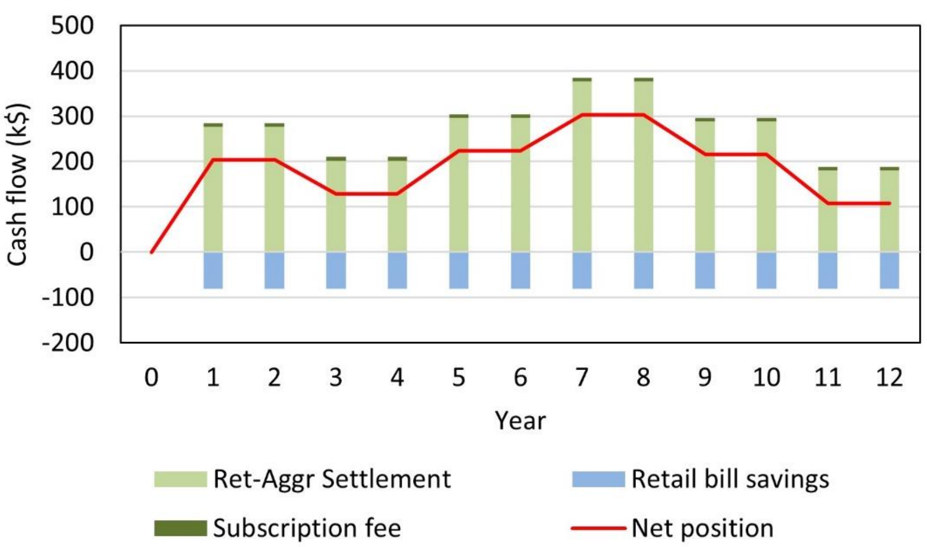


Figure 96. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Retailer" actor under a third-party ownership model-2B.1.

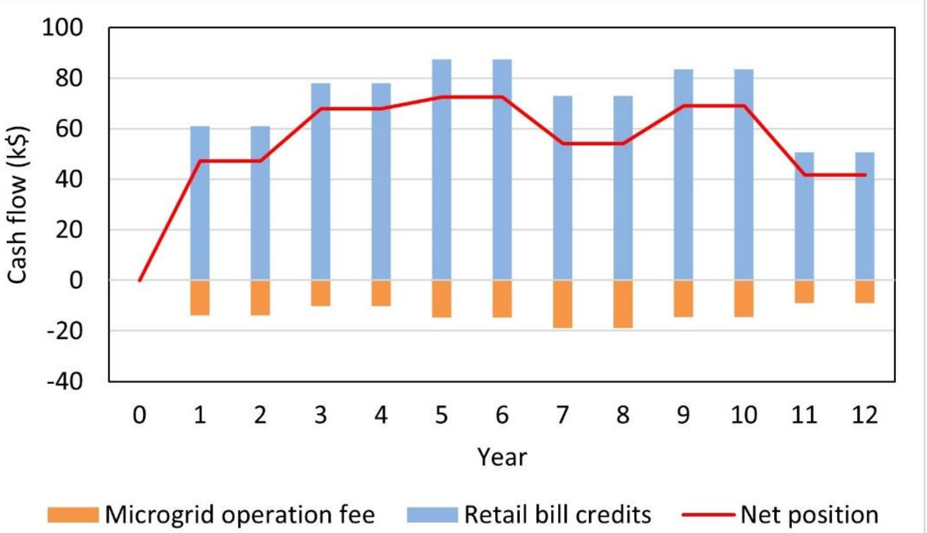


Figure 97. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Tarnagulla community" actor under a third-party ownership model-2B.2.

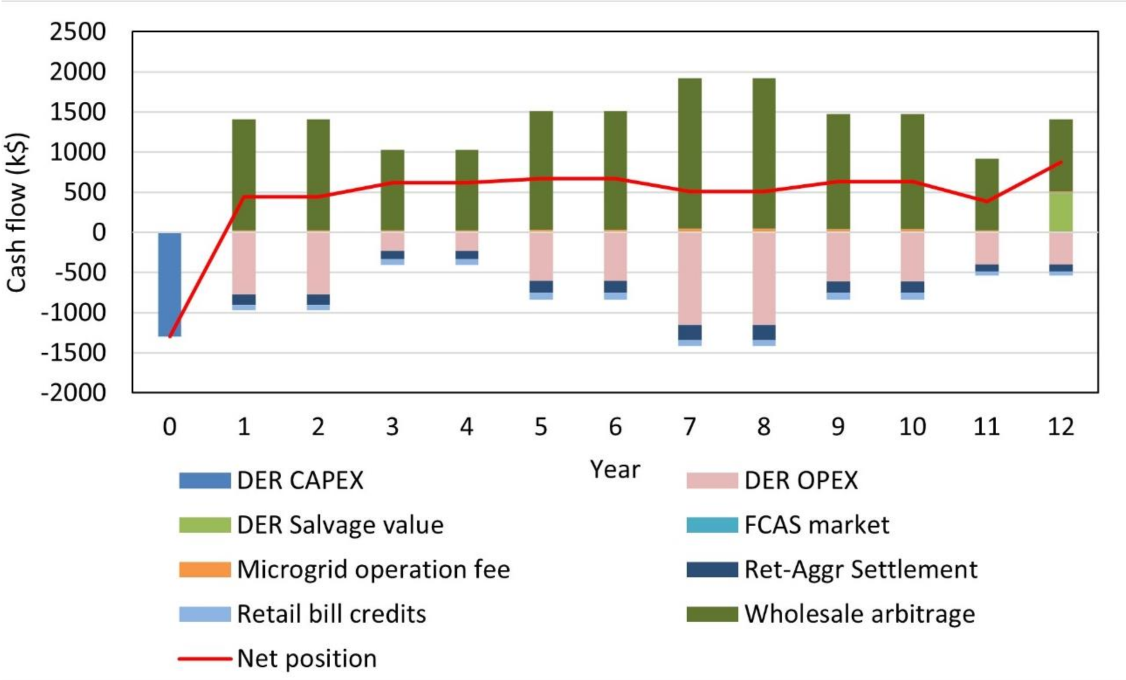


Figure 98. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Independent aggregator" actor under a third-party ownership model-2B.2.

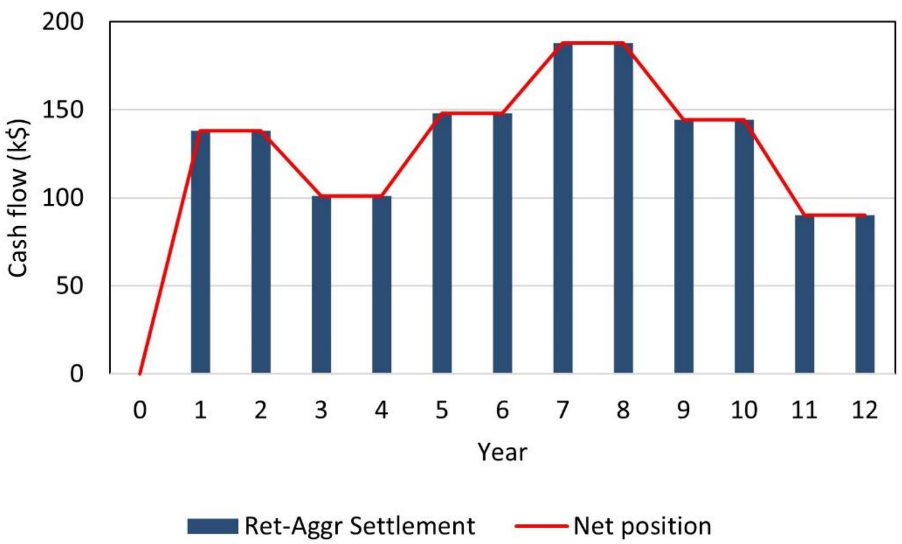


Figure 99. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Retailer" actor under a third-party ownership model-2B.2.

5.4.2.3 Case 3: DNSP-owned with third party operating lease

Under this scenario, Powercor is the actor purchasing the microgrid DER assets and is therefore playing not only the role of DNSP but also the microgrid DER owner. The microgrid DER assets are then leased to the "third-party" actor, who is then the DER lessee while also playing the roles of the retailer, the aggregator and the microgrid operator. This commercial setup would overcome ring-fencing issues and unlock all potential value streams, including those arising from market participation. Under such arrangement, the third-party actor pays the DER owner (i.e., Powercor) a lease fee, which is assumed to be in the form of a share of the revenues, 10% in this example, for the right of accruing the revenues from DER operation while also sustaining the costs for DER operation.

In the guise of retailer, the third party may decide to transfer to its end-customers the benefits accrued as a fixed yearly discount on their retail tariff, calculated as the 60% of retailer's average expected net profit over the microgrid's lifetime. End-customers are entitled to receive such benefit upon the payment of a subscription fee, calculated as 1% of the average expenditure associated to the lease fee over the microgrid's lifetime. With respect the values of the discount rates, the corresponding default values are applied for each actor.

The resulting cash flows, i.e., benefits (+) and costs (-), for the actors under analysis are reported in Figures 100, Figure 101 and Figure 102, with a zoom for the DNSP actor's cash flows depicted in Figure 103.

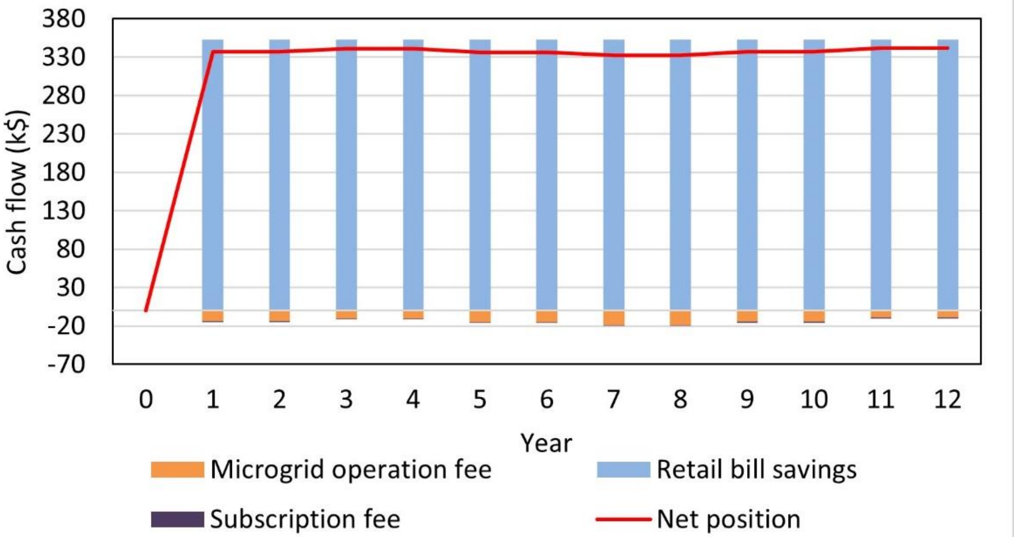


Figure 100. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Tarnagulla community" actor under a DNSP ownership model with operating lease.

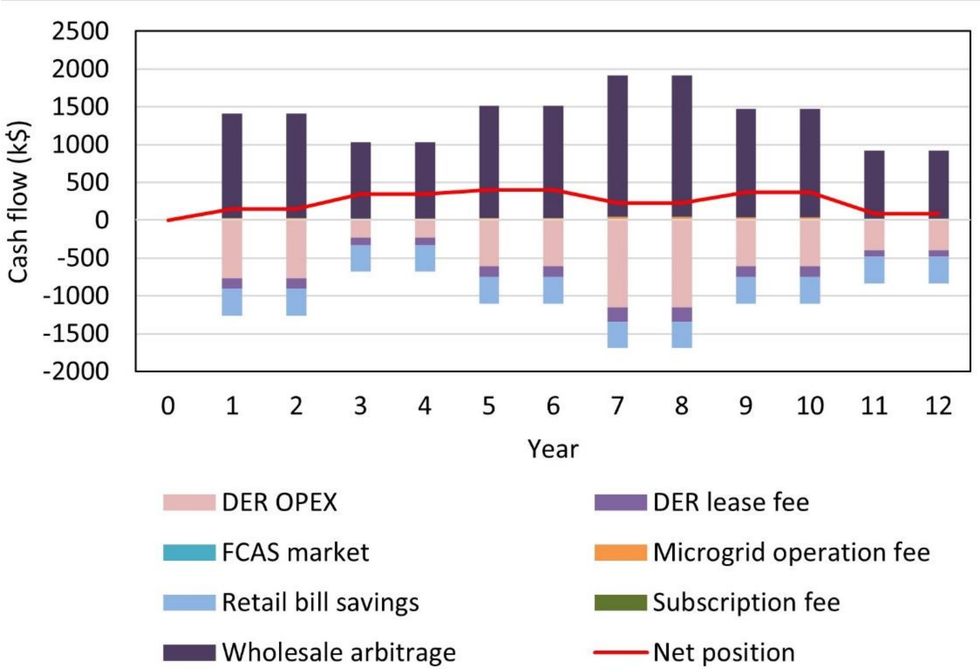


Figure 101. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Retailer" actor under a DNSP ownership model with operating lease.

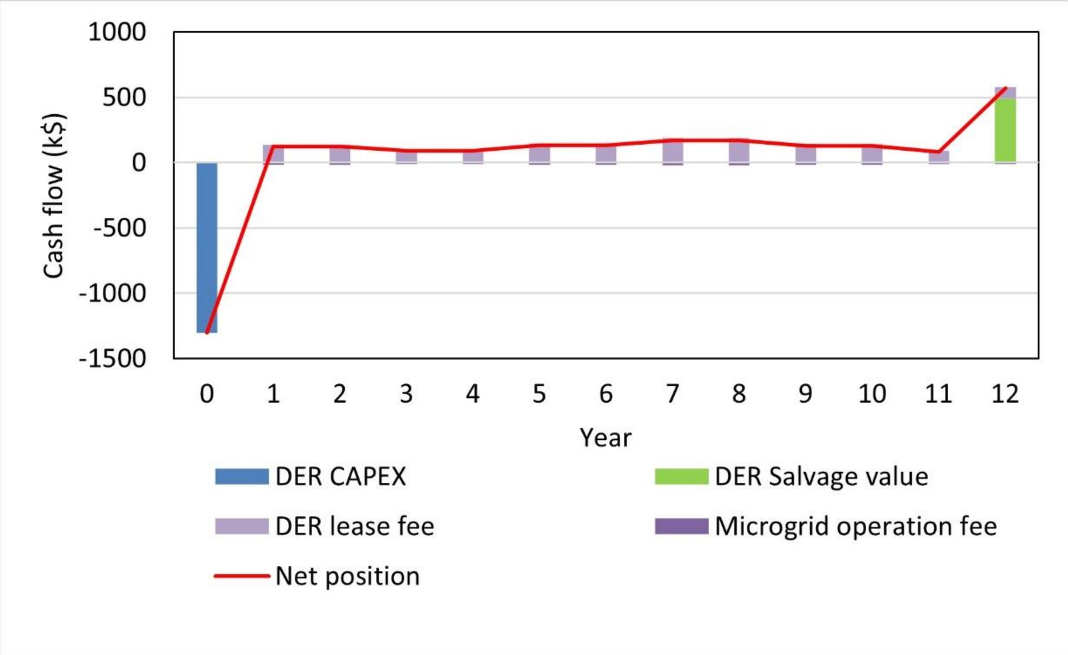


Figure 102. Resulting cash flows, i.e., benefits (+) and costs (-), for the "DNSP" actor under a DNSP ownership model with operating lease.

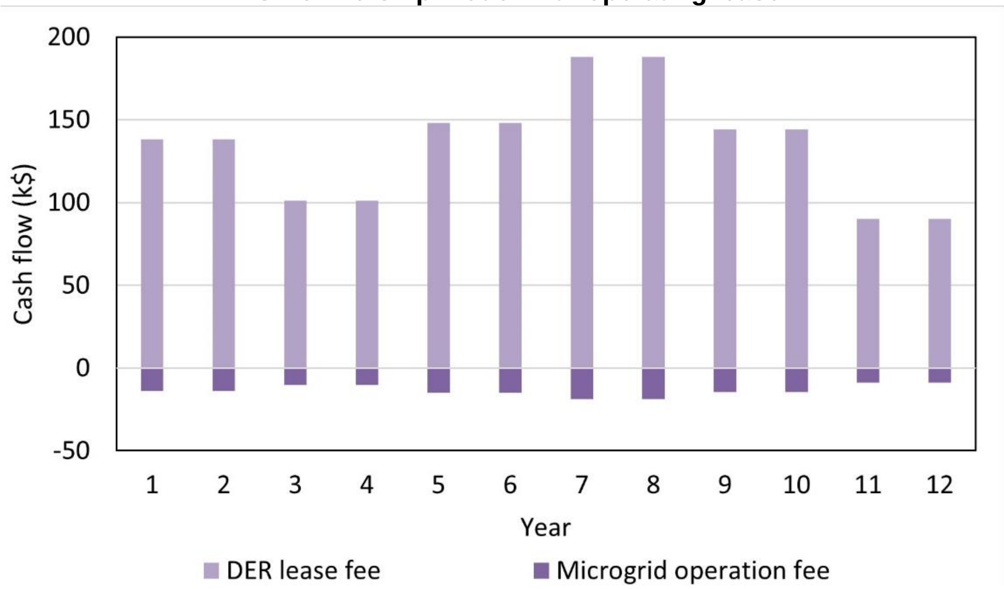


Figure 103. Zoom over the 12 years operation of the microgrid of the resulting cash flows, i.e., benefits (+) and costs (-), for the "DNSP" actor under a DNSP ownership model with operating lease, excluding the DER CAPEX and salvage value financial flows.

5.4.2.4 Case 4: Co-ownership

This scenario envisages both Tarnagulla community and a third-party financially contributing to the purchase of the microgrid DER assets, for the 20% and 80% respectively. As such, they are entitled to accrue the corresponding share of revenues from market participation. Moreover, the third-party is also playing the role of retailer, aggregator and microgrid operator, and as such, receives a payment from the other microgrid actors to be compensated for the service of DER orchestration and market intermediary. This fee is assumed to be equal to 1% of the total markets' revenues.

In this case, because both Tarnagulla community and the third-party are facing market risk while providing the capital to purchase the new microgrid assets, their corresponding discount rates are

increased compared to their default values, to 15% and 10%, respectively, considering the fact that each of them is not fully contributing to the expenses.
The resulting cash flows, i.e., benefits (+) and costs (-), for the actors under analysis are reported in Figure 104 and Figure 105.

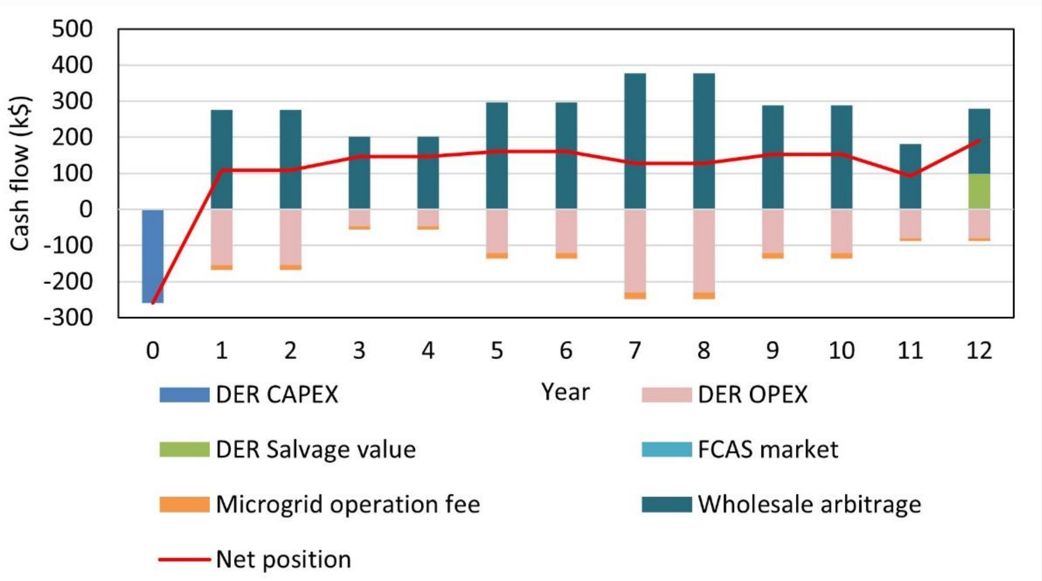


Figure 104. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Tarnagulla community" actor under a co-ownership model.

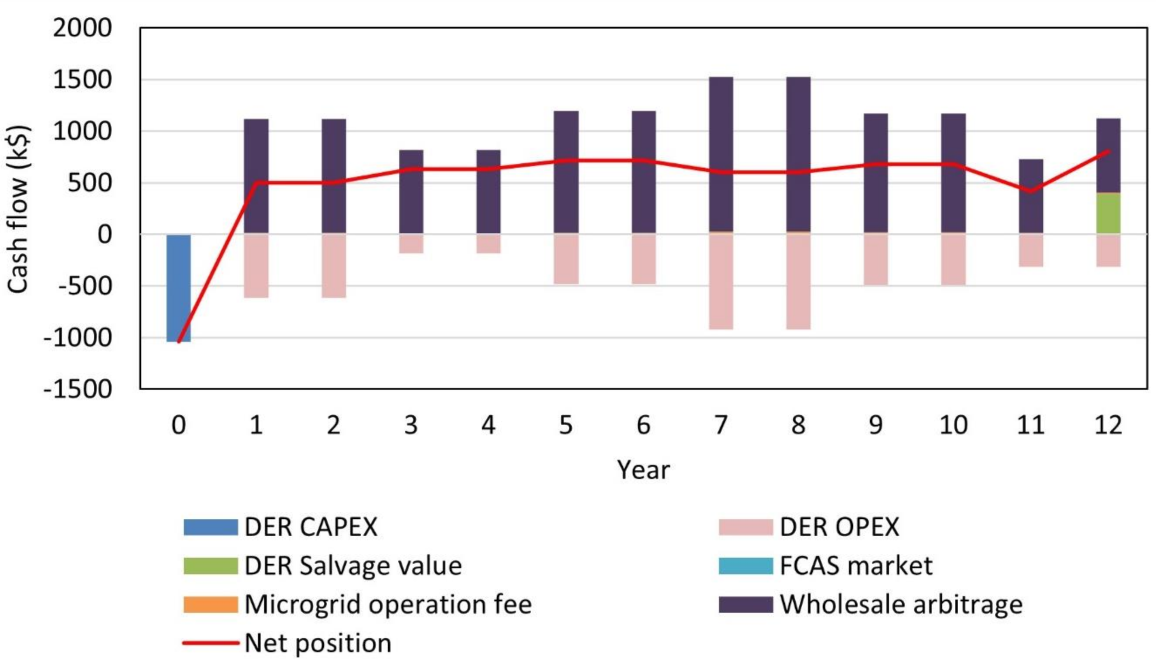


Figure 105. Resulting cash flows, i.e., benefits (+) and costs (-), for the "Retailer" actor under a co-ownership model.

5.4.3 Cost-benefit analysis and results discussion

5.4.3.1 Tarnagulla community

As highlighted in Figure 86, Figure 88, Figure 90, Figure 92, Figure 94, Figure 97, Figure 100 and Figure 104, the community members of Tarnagulla experience different cash flows profiles under alternative commercial strategies. Although under their full or partial ownership, i.e., case 1 and case 4, capital expenditure has a great impact compared to the other cash flows, overall, the benefits that community members are able to accrue over the microgrid operational life are considerable and the favourable markets' conditions result in a positive net position. In fact, a positive NPV can be achieved for this "actor" as displayed in Figure 106, even when a higher discount rate is applied to take into consideration the riskier position community members are in, given markets uncertainty and the considerable capital required for the microgrid to be set up. It should be noticed that the current studies have been performed assuming a zero-bushfire probability condition. However, when the probability of occurrence of bushfires increases, the community would also benefit from the avoided costs associated with the expected energy not supplied, valued at VCR, which would further lift up the net present value of community members.

Under a third-party ownership model, whether it is a retailer actor or an aggregator actor, community members always benefit from discounted retailer tariffs or bill credits. The difference lies in the way these benefits are transferred, with cases 2A.1, 2A.2 and 2B.1 guaranteeing a fixed yearly income to end-customers who are somehow protected from risk, e.g., due to uncertainty in markets' prices. A similar outcome can be seen for case 3. On the other hand, the expected benefits accrued under cases 2A.3 and 2B.2 are not constant throughout microgrid's lifetime but depend on the market conditions. This could potentially increase the risk for end-customers. In fact, the scenario under analysis envisages very favourable markets conditions and therefore the total benefits that the community can achieve are significant.

Resultantly, based on the NPV analysis performed over the different cases, it seems that commercial models where community members are more directly exposed to markets outcomes, such as in cases 1 and 2A.3, are the most favourable from community members' perspective. However, these also represents the most "uncertain" models. This is further confirmed in Figure 107, which shows a comparison of the corresponding NPV under "Central" and "High" prices scenarios (both wholesale energy and FCAS markets) and demonstrating greater deviations and therefore its greater sensitivity to market conditions.

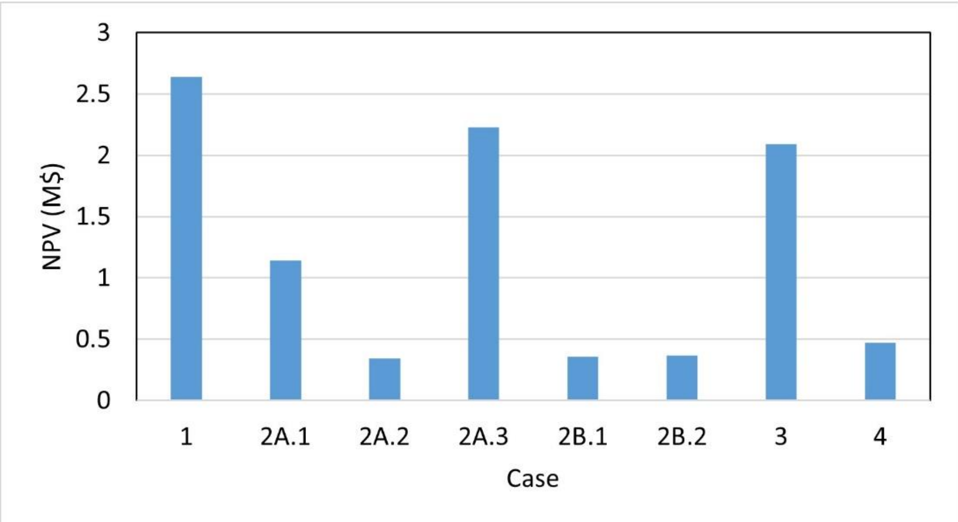


Figure 106. Net present value analysis for the "Tarnagulla community" actor under different commercial models.

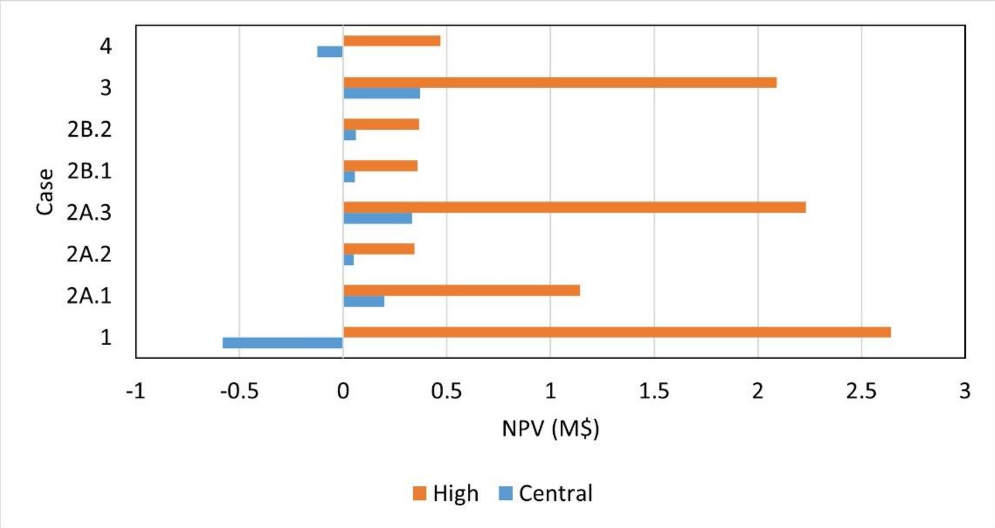


Figure 107. Comparison of the net present value analysis for the "Tarnagulla community" actor under different commercial models for two different wholesale energy and FCAS markets prices scenarios, namely "Central" and "High".

5.4.3.2 Retailer actor

The retailer's net position for case 1 is maintained favourable throughout the microgrid's lifetime as no "negative" cash flow (i.e., cost) is expected, and this is confirmed by the resulting NPV reported in Figure 108. Indeed, this actor is only responsible for DER orchestration and granting access to the different markets and, as such, accrues the microgrid operation service fee as income, as previously displayed in Figure 87. While the case under analysis envisages variable payments, which depend on the outcome from markets participation, a fixed fee can also be contemplated, and this further confirms the "safe" position of this actor.

On the other hand, from case 2A.1 to 2A.3, the retailer is financially responsible for the purchase of the new microgrid DER assets and therefore incurs in substantial capital expenditures. Nevertheless, overall, all three cases show a positive NPV for this actor, as the revenues from wholesale market arbitrage, FCAS market participation, microgrid operation service fee, subscription fee from end-customers are enough to make up for the initial investment, also considering the additional expenses coming from the cost for operating the DER (DER OPEX) as well as the share of benefits transferred to end-customers in the form of retail tariff discount. In this respect, the "retailer-owned" commercial set up that seems the best in this example from end-customers' perspective, that is case 2A.3, leads to the worst outcome for the retailer actor, as demonstrated in Figure 108, with the lowest NPV. In fact, instead of directly passing a pre-defined share of the expected yearly benefits to the end-customers, the strategies adopted to transfer such revenues in cases 2A.1 and 2A.2 follow a more conservative approach which relies on a fixed retail discount structure designed looking at the expected benefits over the 12 years. A similar outcome is expected for case 4 where the retailer contributes to the 80% of the total capital expenditure.

From the retailer's perspective, under these favourable markets' condition, it is clear that a commercial model where this actor fully (or partially) finances the microgrid DER assets is the most favourable, since it will be entitled, as an owner, to a major share of the total microgrid benefits. However, this situation is not guaranteed due to the uncertainty associated, among the others, to markets prices. An alternative commercial model which may bring substantial benefits to this actor and at the same time reduce the risks from "playing" in the markets, is the one outlined in case 3.

The upside of this commercial set up is that this actor is not required to sustain the significant upfront payment to purchase the microgrid DER assets, but rather pays back a DER lease fee to the DNSP which is proportional to the revenues accrued from market participation. Then, based on this, a further share of these benefits may be transferred to end-customers (as a fixed yearly payment) conditional to

a subscription fee. In fact, case 3 is one of the three best options from end-customers' viewpoint as demonstrated earlier in Figure 106.
A similar outcome is expected for cases 2B.1 and 2B.2 where a separate actor, who plays the role of an independent aggregator, bears all the initial capital expenses. In these cases, the retailer's net position is likewise favourable, with case 2B.2 being the least profitable but also the least risky between the two. This is because the only income is related to the settlement payment received by the independent aggregator to compensate for any potential imbalance, compared to the forecasted end-customers net demand profiles, as no discount on the retail tariff is directly applied.

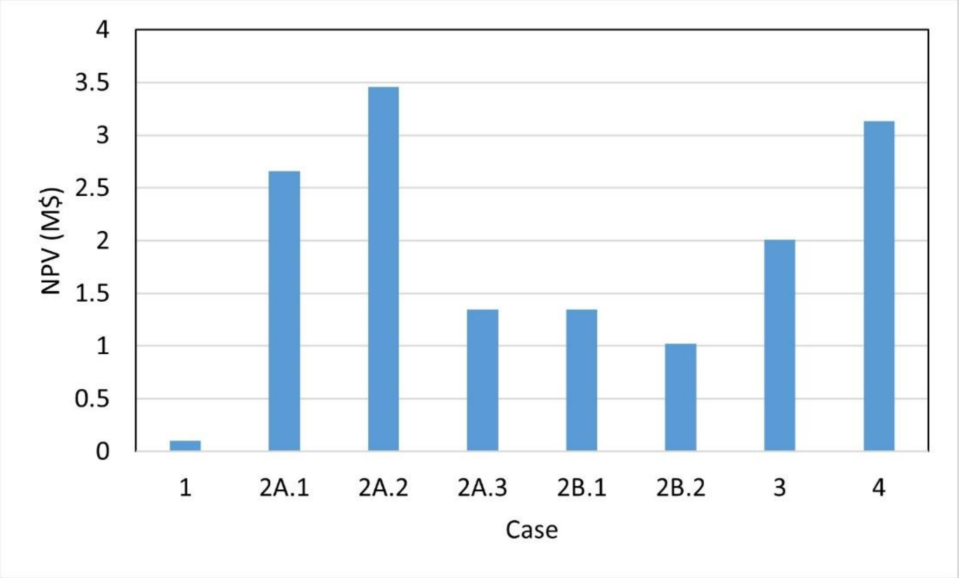


Figure 108. Net present value analysis for the "Retailer" actor under different commercial models.

5.4.3.3 Independent aggregator

When the independent aggregator is the actor who purchases and owns the microgrid DER assets, an additional financial transaction should be introduced to model the settlement payment to the retailer to compensate for the imbalances caused by requesting end-customers to contribute to flexibility, thus posing further risks on the retailer business when procuring energy to meet customers' demand. From the independent aggregator's perspective, directly handling the relationship with end-customers by applying credits on their retail bill rather than having the retailer to adjust their retail tariff appears to be a suitable strategy. Indeed, the risk allocated to the retailer is lower compared to case 2.B.1, and it would be justified to reduce the retailer-aggregator settlement payment.
Overall, for the cases under analysis, the "Independent aggregator" actor benefits from the microgrid, as demonstrated by a positive NPV in both cases 2.B.1 and 2.B.2, as highlighted in Figure 109.

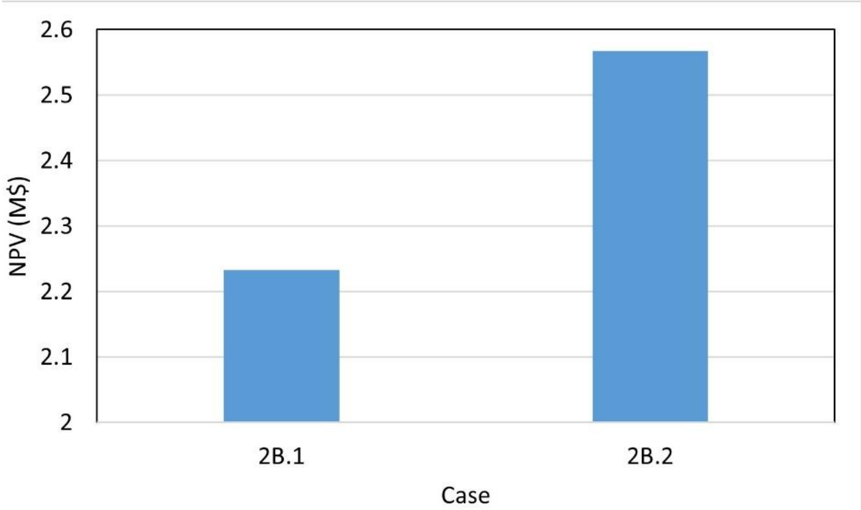


Figure 109. Net present value analysis for the "Independent aggregator" actor under different commercial models.

5.4.3.4 Powercor

For these illustrative examples, the number of different cash flows associated with Powercor as the DNSP are limited. Under the commercial model outlined in case 3, however, Powercor is also playing the role of microgrid DER assets owner, thus sustaining the initial investment costs. As part of the microgrid ecosystem, it is also contributing to the microgrid operation service fee, which accrues to the microgrid operator. To overcome potential limitations to markets participation due to ring-fencing, the microgrid DER are then leased to a third-party. Therefore, the DER lease fee represents one of Powercor incomes. As demonstrated by a zoom of the operational cash flows from year 1 to 12 in Figure 103, despite the limited inflows considered, this actor still achieves a (slightly) positive net present value.

In fact, because there is no planned network upgrade/investment in the area under analysis, there is no additional value from deferring additional capital expenses associated with network infrastructure upgrades. This could indeed represent a major benefit which could further boost the business case for the DNSP to also be the owner of the microgrid DER.

Moreover, the capital investment made by the DNSP in the microgrid DER, not only contributes to meet the energy needs of the community, but also leads to a more reliable delivery of electricity, especially in extreme events conditions, to the end-customers.

Therefore, if for example end-customers are willing to reward[13] Powercor for such improvement by paying an equivalent of a percentage, e.g., 5%, of the savings of expected energy not served (EESN) costs (valued at VCR), unlocked by the microgrid implementation, this would represent an additional income that could lift up the DNSP financial position.

In the event of no bushfire occurring over the 12 years of microgrid operational lifetime (and therefore the EENS cost savings would not "materialize"), to be guaranteed at least a condition of marginal profitability, for this example Tarnagulla community members would not be willing to pay more than ~23% of the EENS cost savings, as demonstrated in Figure 110. In turn, if an extreme event actually presents itself, the benefits from EENS cost savings would materialize, thus further increasing community members' NPV.

[13] Conditional to amendments in DNSP revenue caps allowed by the Australian Energy Regulator.

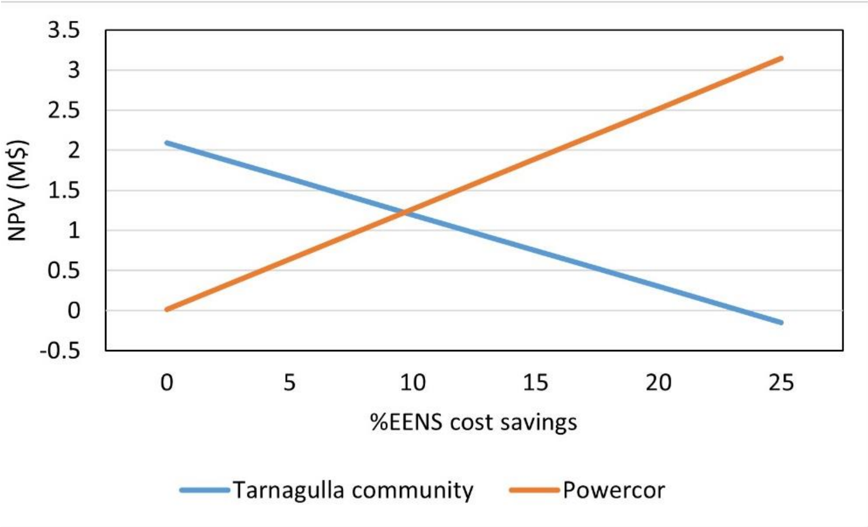


Figure 110. Sensitivity of "Powercor" and "Tarnagulla community" actors' NPV with respect to the payment for reliability benefits, modelled as % of the total EENS costs savings.

5.4.4 Key insights from the commercial framework

A summary of each actor's net present value and (discounted) payback time under different commercial models analyzed in section 5.4.2 are reported in Figure 111 and Figure 112. The figures show how, for these illustrative examples, case 3 results as the most "balanced" commercial model where both the community members and the third-party benefit from setting up the microgrid while the DNSP sustains the capital costs for purchasing the microgrid DER assets. While this only leads to a slightly positive net present value for this actor, there are potentially additional benefits that the DNSP might be able to accrue, although not included in this example, such as the avoided costs for procuring network support services from a third party, along with avoided capital investment on network infrastructure upgrades.

Although the option of having community members directly purchasing the DER assets may be financially feasible, the preference towards having the DNSP as an investor is further supported by its considerably lower cost of capital than the other actors under consideration, and particularly the community members.

In fact, the financial strength of the distribution network service provider combined with the experience, access to markets information of a competitive market participant, e.g., retailer and/or aggregator, has great potential for the development of microgrids which ultimately brings significant benefits to the community, particularly when taking account of the possibility of extreme weather events for which the reliable delivery of electricity to end-customers may be compromised.

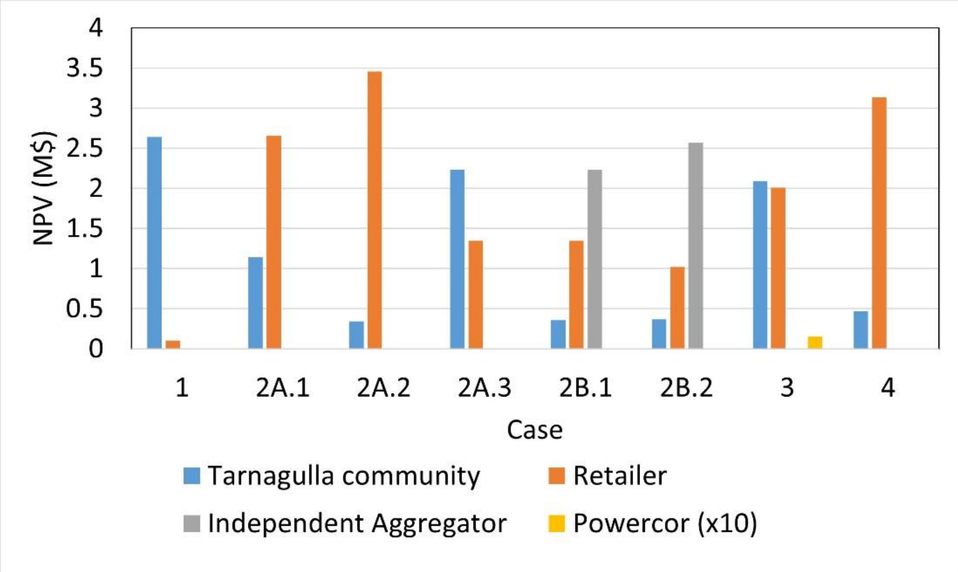
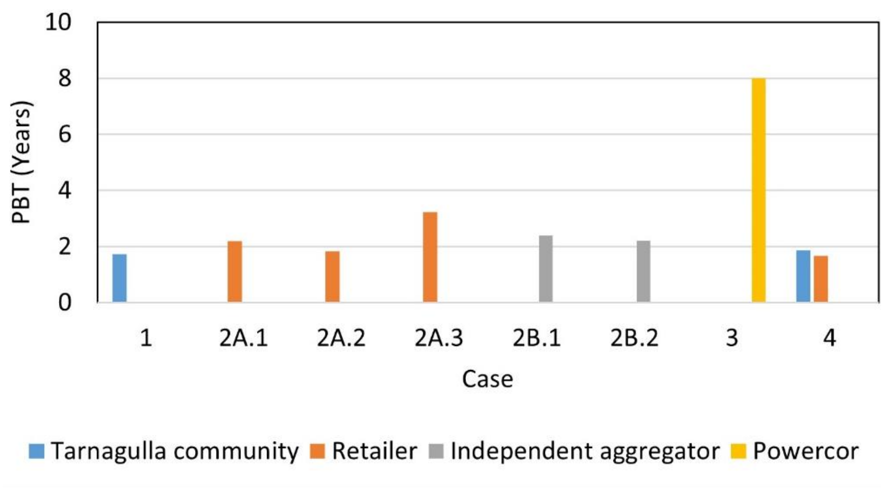


Figure 111. Summary of each actor's net present value under different commercial models under analysis. The NPV value of "Powercor" actor is multiplied by 10 for visualization purposes.

(a)



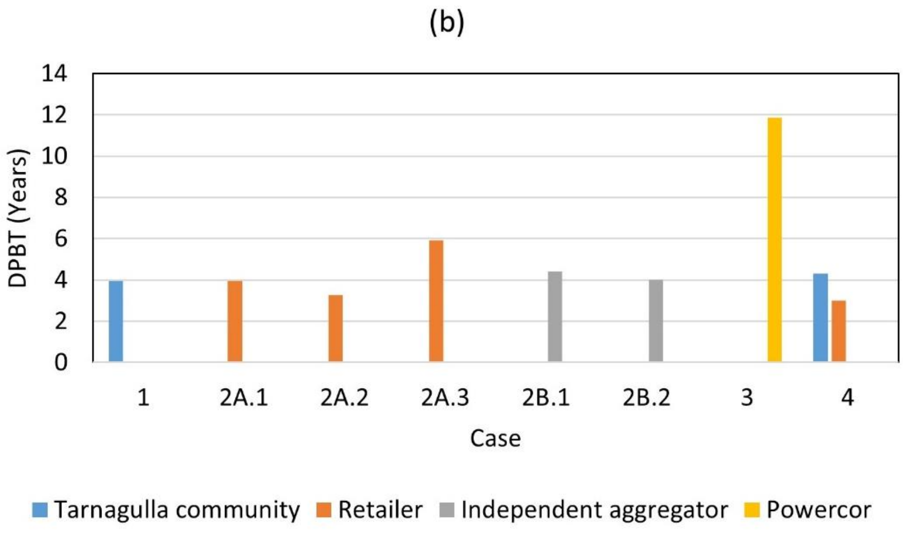


Figure 112. Summary of payback (a) and discounted payback (b) times of each microgrid DER investor under different commercial models under analysis.

6 Summary and Conclusions

Project 8 was performed by a collaboration between the University of Melbourne and Federation University. This report ("Project 8: Economic and Risk Assessment – Part I") has presented the work performed by the University of Melbourne, while detailing when required the contributions from the work performed by Federation University. Further detail on the work performed by Federation University can be found in the report "Project 8: Economic and Risk Assessment – Part II". The following are the conclusions from the Economic and Risk Assessment study performed by University of Melbourne:

- Project 8 has presented a techno-economic framework comprised of an integrated investment and operation model and an operational model. These models allow the inclusion of the MV network of each town, allowing to include in the investment decisions the impact of the MV network within each town (e.g., network constraints, locations with higher and lower demand and PV generation), and in turn provides more accurate estimates on the microgrid costs and benefits as well as allowing to inform on preferred DER locations in each town as compared to previous studies. Additionally, the impact of uncertainty in future system-level and local conditions can be included in the modelling, which enables an improved understanding on the conditions in which the microgrid can provide further value. Importantly, the modelling includes the different roles and responsibilities within the microgrid (such as customers, distribution network service provider (DNSP), microgrid operators, aggregators) and their respective costs and revenues. This allows to consider further system-level and local value streams that are included with high time granularity capturing extreme conditions where microgrids can provide significant value. Moreover, the impact of extreme weather events as well as the microgrid operation in normal conditions is considered in the microgrid investment decisions. In summary, the techno-economic framework presented enables a comprehensive understating of the aggregate value the microgrid project provides.
- When not considering the impact of bushfires, required investment on PV systems is limited for both towns. However, as more severe bushfires occur with more frequency, investment on PV systems and battery systems are recommended to support the microgrid operation during the bushfire events given the parametric studies provided by Project 7.
- Wholesale market prices are the main uncertain parameter that drives the required microgrid investment, as savings arising from wholesale market arbitrage is the main source of revenues for the microgrid. In both Donald and Tarnagulla the microgrid integrated investment and operation model recommends relatively small diesel generators to withstand price spikes when wholesale markets are generally not high and volatile (e.g., central wholesale market scenario) and for high and volatile wholesale market prices the installed capacity of diesel generators significantly increases.
- Diesel generators are generally recommended as cost-efficient investment decisions that can be dispatched at times of price spikes in the wholesale market, providing significant benefits to the community. However, a community might not have a positive attitude towards diesel generators due to their environmental impact. When diesel generators were not considered as an investment option, investment in batteries significantly increased. While not considering diesel generators results in higher costs for the microgrid project it can come with additional benefits beyond environmental aspects. A key assumption around diesel generators is fuel cost (equal to $300/MWh) which was assumed to remain constant through the economic assessment horizon. This might not be the case, and the results displayed that higher fuel costs (around $400/MWh, higher or lower depending on the case study) make the final economic position of the microgrid not including diesel generators equal or more favourable than when diesel generators are included. Therefore, not investing in diesel generators might also be favourable avoiding an additional source of uncertainty which are fuel prices or future costs coming from regulatory developments to reduce carbon emissions.
- In most scenarios battery systems were recommended, as these are flexible resources that can provide an array of benefits to the microgrid. In Tarnagulla, 1 hour duration batteries are systematically selected, whereas in Donald we see batteries of 2 hour duration in the Central wholesale market price scenario and 1 hour duration in the High and Volatile wholesale market price scenario. It must be noted that the battery sizes recommended for Donald in the

Central wholesale market price scenario are significantly larger when compared to the remaining cases. This might point out that larger batteries are more suited for longer durations, whereas smaller batteries (<4 MWh) are better suited for shorter durations in both microgrids.

- In Tarnagulla, the inclusion of bushfires using EENS has a relevant impact on the investment decision. However, in Donald it is not the case. Donald is a larger system that needs to supply further demand. The possible savings from purchasing energy from the wholesale market drives the investment decisions, and when considering the EENS costs, the selected resources effectively reduce the EENS costs to optimal levels, according to the parametric studies from Project 7.
- When dealing with uncertain future scenarios, stochastic decisions that intrinsically account for uncertainty provide valuable insights. Stochastic investment decisions provide the optimal decision to withstand uncertainty, and in this case provide robust solutions for different future wholesale market price scenarios., which are the main uncertainty source affecting microgrid investment decisions. Stochastic decisions displayed that if a credible future scenario consists of high and volatile wholesale market prices, the risks associated with purchasing energy to meet the microgrid local demand in this scenario drive the investment decision. However, in the event wholesale market prices followed a less volatile evolution, the costs and revenues arising from further investment on DER will still be acceptable.
- When designing a microgrid including the impact of bushfires using EENS, the probability associated with bushfires is a critical parameter. When design considers higher probabilities of bushfire occurrence, investment decisions significantly change from the design without considering the impact of bushfires. Additionally, the impact of assumptions such as PV efficiency during the bushfire, fuel disruption or presence of customer-owned DER will have a relevant impact on the optimal investment decisions.
- When designing a microgrid in a region where severe bushfires are likely to take place, directly including in the investment model credible bushfire events is a critical step to understand the required optimal investment during the event. Severe bushfires, like the two-week bushfire with one week fuel disruption included in the analysis, can yield to actual energy not served that entails unacceptable costs. This was highlighted in the regret analysis, were the investment decisions that considered the costs associated with EENS in the actual bushfire event resulted in high costs of energy not served, and thus high regrets associated with the investment decision.
- Regarding the microgrid operational results, wholesale market savings is the main source of revenues for the microgrid. The microgrid DER can supply a large share of the local demand, avoiding to purchase energy from the wholesale market, as well as providing wholesale market arbitrage and exporting power at times of high prices.
- Additional value streams can incentivize the microgrid DER to provide valuable services such as peak demand reduction, demand response, network tariff arbitrage or voltage management services. However, these value streams only comprise around 10% of the annual NCF and are not the main factor for the microgrid profitability. Nevertheless, as compared to system-level markets such as FCAS or wholesale market that have highly uncertain future evolutions, these additional value streams provide a consistent source of revenues for the microgrid during its lifetime.
- The NPV analysis considering both investment and operational cash flows displays that the microgrid project in Donald and Tarnagulla can provide value to the community and different stakeholders involved, especially when considering the economic impact of bushfires.
- Donald displays larger NCF and NPV compared to Tarnagulla. However, when normalizing the NPV with respect to the energy demand in each town the value the microgrid can provide with respect to “each GWh of energy demanded in the community” can be understood. This normalized NPV displays fewer striking differences between the two towns. However, when considering the impact of bushfires Donald provides considerable more value per “GWh of demand” than Tarnagulla due to the synergies between optimal investment decisions for “normal operation” and to reduce bushfire impact.
- The techno-economic performance of central DER and distributed DER operated in a coordinated manner result in similar annual NCF. While the distributed DER outperforms the central DER by 62 $k during a year, if additional costs of maintenance, control costs and

benefits of economies of scale of central DER beyond the scope of this project are considered, central DER might result in a more adequate investment.

- Network tariffs charged at microgrid-level can incentivize the cost-efficient use of the network, yielding to savings while the microgrid provides different technical benefits (i.e., reduction of peak demand and importing energy at favourable times). However, by charging a network tariff at microgrid-level the costs of the network inside the microgrid are not accounted, also leading to significant reduction of recovered costs for the DNSP. In Tarnagulla, the microgrid requires the upstream grid to support its operation, displaying a consistent operation throughout seasons during its lifetime. This allowed to propose the use of microgrid-level tariff + LUoS as an avenue to facilitate the benefits from the cost-reflective microgrid-level network tariff, while also acknowledging the costs of the MV and LV networks within the microgrid. Given the microgrid operational model and the case study selected it was found that a 5.26 cents/kWh flat rate LUoS for customers within the Tarnagulla microgrid would result in equal network charges to the BAU case, where network charges are only applied at customer level. In this specific case study, this would be the maximum acceptable LUoS that would ensure customers are not subject to higher costs as a result of being part of a microgrid (assuming the microgrid-level network charges would also be paid by customers).
- In the case of Donald, by including the microgrid-level network tariff, we consistently perceive seasonal differences through its lifetime. During fall and winter months the microgrid in Donald is economically incentivized to operate islanded. These relevant seasonal differences comprise a more challenging case, where annual and lifetime average network charges cannot reflect the significantly different microgrid operation. Therefore, it is not adequate to propose a solution equivalent to Tarnagulla where consistent microgrid-level network charges allow to estimate adequate LUoS during its lifetime. Further analysis on possible regulatory frameworks for network tariffs suited for microgrids with significantly different operational behaviours within seasons should be carried out.
- Among the business models presented “DNSP-owned with third party operating lease” results as the most “balanced” commercial model where both the community members and the third party benefit from setting up the microgrid while the DNSP sustains the capital costs for purchasing the microgrid DER assets. While this only leads to a slightly positive net present value for this actor, there are potentially additional benefits that the DNSP might be able to accrue, although not included in this example, such as the avoided costs for procuring network support services from a third party, along with avoided capital investment on network infrastructure upgrades.
- Although the option of having community members directly purchasing the DER assets may be financially feasible, the preference towards having the DNSP as an investor is further supported by its considerably lower cost of capital than the other actors under consideration, and particularly the community members.
- The financial strength of the distribution network service provider combined with the experience, access to markets information of a competitive market participant, e.g., retailer and/or aggregator, has great potential for the development of microgrids which ultimately brings significant benefits to the community, particularly when taking account of the possibility of extreme weather events for which the reliable delivery of electricity to end-customers may be compromised.

7 References

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