Stakeholder Impact Investigation

Final Report

Donald and Tarnagulla Microgrid Feasibility Study

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Glossary

Abbreviation	Definition
ACL	Australian Consumer Law
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ATA	Alternative Technology Association
CALC/CUAC	Consumer Action Law Centre & Consumer Utilities Advocacy Centre
CEC	Clean Energy Council
COAG	Council of Australian Governments
DNSP	Distribution Network Service Provider
ECA	Energy Consumers Australia
EMTPT	Energy Market Transformation Project Team, reporting to SCO
ENA	Energy Networks Association
ETU	Electrical Trades Union of Australia
EWON	Energy and Water Ombudsman, New South Wales
NECF	National Energy Customer Framework (implemented by the NERL)
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules, made under the NEL
NERL	National Energy Retail Law
SAPS	Stand-alone Power System
SCO	Senior Committee of Officials, reporting to the COAG Energy Council
RAB	Regulatory Asset Base
RIT-D	Regulatory Investment Test - Distribution
DGs	Diesel gensets
SAIFI	System Average Interruption Frequency Index
SAIDI	System Average Interruption Duration Index
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
ENS	Energy Not Served
AENS	Average Energy Not Supplied
NPC	Net Present Cost
COE	Cost of Energy (Levelised)
O&M	Operational & Maintenance Costs

CRCI	Combined Reliability and Cost Index
LPIF	Load Point Interruption Frequency
LPIT	Load Point Interruption Time
ACIF	Average Customer Interruption Frequency
ACIT	Average Customer Interruption Time
TCIF	Total Customer Interruption Frequency
TCIT	Total Customer Interruption Time
LPENS	Load Point Energy Not Supplied
ASIFI	Average System Interruption Frequency Index,
ASIDI	Average System Interruption Duration Index,

1. Executive Summary

This project addresses parts of a feasibility study for microgrids in two regional Victorian towns Donald and Tarnagulla (***the study***) under the Federal Government's Regional and Remote Communities Reliability Program Fund – Microgrids Fund 2019-20 Grant. The study is awarded to Centre for New Energy Technologies (C4NET). Swinburne University of Technology in collaboration with C4NET, RMIT University, and Powercor have conducted an investigation into the stakeholder impact of microgrids at Donald and Tarnagulla (***the project***). These two regional Victorian towns have been experiencing supply vulnerabilities. The project aims to investigate the impact of microgrids (in terms of economics, reliability, sustainability, and regulatory) on different stakeholders under various scenarios of loads to be supplied when there is a transition from the microgrids being grid-connected to islanding in these two towns. The outcomes of this project will be utilized in the other parts of the study of this feasibility study to provide the communities with potential alternative solutions for their energy supply.

This project has been divided into three major tasks, and the detailed results and outcomes of these tasks are provided in this report. In the first task, the smart meter data from the distribution networks in the Donald and Tarnagulla areas have been analysed to identify the most common load profiles for different customer types. Based on these different load profiles, we have also developed several scenarios of the customers in the area to establish the optimal microgrid configurations under each scenario in terms of economic and reliability impacts on different groups of customers.

In the second task, a framework (including the architecture) and market mechanisms for an automated trading platform in smart microgrids was developed. A comprehensive appliance modelling to simulate the load profile according to the smart meter data was constructed. Based on a set of assumptions regarding the customers' preferences/utility functions and the cost of supplying the energy, a market mechanism can be introduced to align the customers' objective of maximizing their own benefits with the system objective of maximizing the total welfare via dynamic pricing.

Finally, the regulatory environment into which microgrids are entering is extremely complex, in part because they encroach on multiple areas of existing regulation not conceived with them in mind, i.e., generator interconnection rules, air quality permitting, building codes, tariffication, etc. Thus, regulations present a barrier for a microgrid being established in Donald and Tarnagulla and, more generally, in other areas in Victoria. Subsequently, in the third task, regulatory requirements for de-energising and re-energising the microgrid and its loads are investigated.

Each key findings and conclusion are provided at the end of each section of this report and summarized in **Section 8**.

Major findings and recommendations from the research and analysis are presented below:

1. **Task 1: Techno-economic analysis for different combinations of technology integration and associated power quality and reliability assessment:**
    a. To understand the impact of microgrids on the customers in these two areas, it is essential to analyse the importance of various types of customer loads and the ability of the microgrids to supply these loads under different conditions. Due to a range of issues, detailed customer by customer data was not available for analysis. Therefore,[1] to investigate different scenarios of load priority and the associated microgrid designs we have adopted a simplified classification of loads: **Community critical loads**, **Medium-flexibility loads**, and **High-flexibility loads**. We have simulated many different scenarios to provide a basis for in-depth analysis into the impacts microgrids of different sizes and designs can have on each load type.
    b. We carried out comprehensive analysis of different combinations of technology integration such as PV/Battery/DG, PV/Battery, and PV/DG and arrived at the following conclusions:

i. The integration of PV/Battery/DG is the best integration (in terms of economics, sustainability and power quality and reliability) for creating microgrids in Donald and Tarnagulla regions. For this configuration, the project lifetime is assumed to be 25 years[2] and the techno-economic analyses for these two areas are conducted by considering the simulated scenarios.

ii. The designed microgrids will be connected to the main utility grid to minimise the reliance on diesel gensets (ensuring cost saving and utilisation of renewable energy).

iii. In the events of utility grid outages or when the utility grid is not providing sufficiently stable power, appropriate microgrid control systems (MGCS) technology can ensure seamless transition between grid-connected and island operating modes. When in island mode, microgrids provide on-site power generation that supports facility operations indefinitely for the designated loads, until utility service can be restored. When in island mode, DGs may need to operate if the designated loads cannot be met by the generation of the PVs and the battery. This can lead to the cost of energy (COE) during the island mode of operation to be quite high. For instance, for the Donald area and only critical load needs to be supplied, COE = $0.344/kWh for a specific hypothetical scenario.

c. The reliability and power quality assessment were conducted for the two aspects of *power security assessment* and *generation adequacy assessment*:

i. *<u>In terms of power security</u>*: If the microgrid is to be operated for the entire year in the island mode, the average number of outages is: 2.73 per year, with the total duration of outage is 14.7 h. If the microgrids is connected to the utility grid and only needs to operate in the island mode when the utility grid outages occur or when the utility grid is not providing sufficiently stable power, the above probability of outage is sufficiently small and thus we can conclude that, under the condition that appropriate microgrid control systems (MGCS) technology has been installed and DGs have sufficient fuel supply, the designated loads of the microgrid are guaranteed to be supplied.

ii. *<u>In terms of generation adequacy</u>*: This analysis mainly about the accessible enough energy by considering availability, unavailability, and possible outages of PVs, batteries, and DGs. To conduct this analysis, the duration of availability for PVs, batteries, and DGs is considered as 10 hours in one complete day (i.e. in 24 hours) and the integration of PVs, batteries, and DGs are incorporated to serve the loads. Based on the analysis, it can be shown that, under the studied scenarios, if the areas are isolated from the utility grid and the areas are served by only the integration of PVs, batteries, and DGs, the installed capacities are sufficient to continuously serve the communities' customers.

2. **Task 2: Analysis of customer's flexibility regarding the supply security for the different loads in their household or at their business**: To understand how a specific customer can be affected by the installation of a microgrid in terms of the utility they gain from having the electricity supplied and the cost of energy they have to pay, we conducted an analysis of customer's flexibility regarding the supply security for the different loads in their household or at their business. We were not able to obtain a real-world appliance model from the two areas (Donald and Tarnagulla), nor were we able to obtain the customers' preferences/utility functions associated with each NMI. Subsequently, we have also simulated a comprehensive appliance model for the hypothetical customers of the microgrid and made some assumptions around their preferences to simulate a utility function for each customer. The simulated appliance model covers a comprehensive range of appliances including: temperature-based appliances

[2] The assumption of the project lifetime of 25 years is based on the standard warranty provided by PV panel providers in Australia.

(such as air conditioner and refrigerator), deadline-based appliances whose usage can be shifted within a time window as long as their usage can be done before their respective deadlines (such as electrical vehicles, dish washer, clothes washer), time-based appliances whose usage is required at the time the customer needs them (such as lighting) and also time-and-usage-based appliances (such as computers, entertainment units – TVs, audio speakers). Based on the studied what-if scenarios, we have conducted a detailed analysis to demonstrate the impact of demand response (realised via the dynamic pricing in the developed market platform) on the loads in the microgrid. Specifically, there is a clear peak-load flatten when dynamic pricing has been applied. An important observation from this analysis is that: Not all loads are equal. Some loads can be shedded and some loads can be shifted to a different time for the purpose of flattening the overall peak load for the purpose of cost saving. Therefore, careful analyses can be conducted to provide insights into the following: (i) *what is the flexibility a customer can have regarding the supply security for the different loads in their household or at their business (by translating such a flexibility to monetary cost associated to not having those loads supplied)*? and (ii) *if certain constraints are in place for the microgrid generation capacity, what would be the impacts of such constraints on a specific customer (especially business customers) for their loads not being supplied*? A software tool for carrying out these analyses has been developed and will be provided to C4NET. However, to conduct such an analysis, we will need the data about the customers' energy consumptions and their preferences on the consumption of different loads within their household/business. We envisage that **Project 49.02** (**Community Engagement**) will provide the customers' preference profiles and **Project 49.05** (**Islanding Design and Cost Analysis**) will provide the energy cost function for energy supply in the microgrid both in the grid-connected mode and islanded mode of operation.

3. **Task 3: Regulatory requirements for de-energising and re-energising the microgrid and its loads:** While development of technologies and technical standards for microgrids have sufficiently matured to enable microgrids to be installed and operated, regulations have been considered the biggest barriers to the development and adoption of microgrids in most jurisdictions because they encroach on multiple areas of existing regulation not conceived with them in mind, i.e., generator interconnection rules, air quality permitting, building codes, tariffication, etc. To understand the regulatory requirements for microgrids, we undertook several studies: (i) A comprehensive review into existing regulatory framework in Victoria and in Australia as well as in other jurisdictions; (ii) A comprehensive reviews into technical standards and requirements for interconnection/ de-energisation/ re-energisation of microgrids and associated loads/generation; and (iii) A study into existing microgrid projects and demonstrations around the world for insights and lesson learns. Subsequently, we provide a list of recommendations for regulatory bodies in Australia and Victoria regarding the introduction and adoption of regulatory requirements for de-energisation and re-energisation of microgrids.

2. Project Background and Objectives

This project is part of a larger study to assess partial or full microgrid feasibility in two regional Victorian towns (Donald and Tarnagulla) with supply vulnerabilities. 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 through alternative energy resources such as solar and battery storage. Swinburne University of Technology in collaboration with C4NET, RMIT University, and Powercor have investigated stakeholder impacts for the proposed microgrid facilities at Donald and Tarnagulla.

A community microgrid (such as the ones considered in this feasibility study for the areas of Donald and Tarnagulla) can bring about many important benefits: providing backup for the grid in case of emergencies (and thus, improving power security and reliability), potential cost saving (through the utilisation of renewable resources such as solar/wind energy), and enabling connection to a local resource that is too small or unreliable for traditional grid use, especially intermittent generation sources such as wind/solar energy (and thus, improving sustainability). However, it is essential to conduct a detailed analysis into these different aspects for these communities through a customised microgrid design and optimisation for the areas of Donald and Tarnagulla. This project aims at understanding the impacts microgrids may have on the stakeholders in the region (including residential and business customers) in terms of reliability, resilience, sustainability, and cost for the proposed microgrid facilities at Donald and Tarnagulla where various scenarios for supply requirements are considered, modelled and analysed. This project explores different mixes of generation technologies, such as solar, diesel, and storage as well as different categories of load requirements. Furthermore, this project also undertakes a review of existing regulations with regard to de-energising and re-energising the micro-grid as well as the loads within the microgrid.

3. **System Modelling and Stakeholder Identification**

This section presents an overview of the electricity grid distribution networks in the two areas to be considered in this study (Donald and Tarnagulla) including simplified single-line diagrams of the networks which will be used in our technical analyses in this project. Furthermore, to carry out technical analyses into the impact of microgrids on different stakeholder groups and with the availability of only the de-identified smart meter data, we conducted various data analysis techniques (including EDA and PCA) to obtain needed insights into the different customer groups in the areas of study.

3.1. Donald Network

A single line diagram of Donald town connected to the electricity grid is given in **Figure 1** and simplified as **Figure 2**. The Donald town is within the boundary marked in **Figure 1**. It can be observed that Donald is connected to the main grid through the Charlton line. There are a number of load points along the Charlton line. Therefore, while optimizing the Islanding location, it is crucial to consider the actual load points along the Charlton line, because the load points connected to the far end of the line (closest to Donald town) is the same as the first load point in Donald town. Hence, the quality and reliability of supply to the loads connected across the Donald line would help to optimize the Islanding location point.

It is worth noting that two areas, i.e., Litchfield and Donald South, are also supplied through Donald town. Therefore, islanding the Donald town essentially means the islanding of Donald, Litchfield, and Donald South. There are several loads connected in those areas. Therefore, the actual system model development for those areas is also vital to study the reliability and quality of supply. Using lumped loads for these areas might not give accurate results. Detailed models of the Donald line, Donald town, Litchfield area, and Donald South area are developed in DIgSILENT Power Factory software.

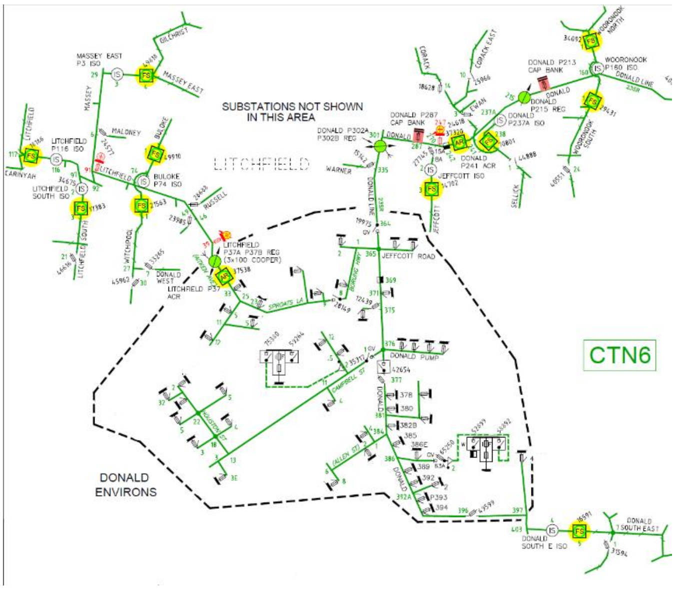


Figure 1: Donald town connected to the grid (with downstream Litchfield and Donald South)

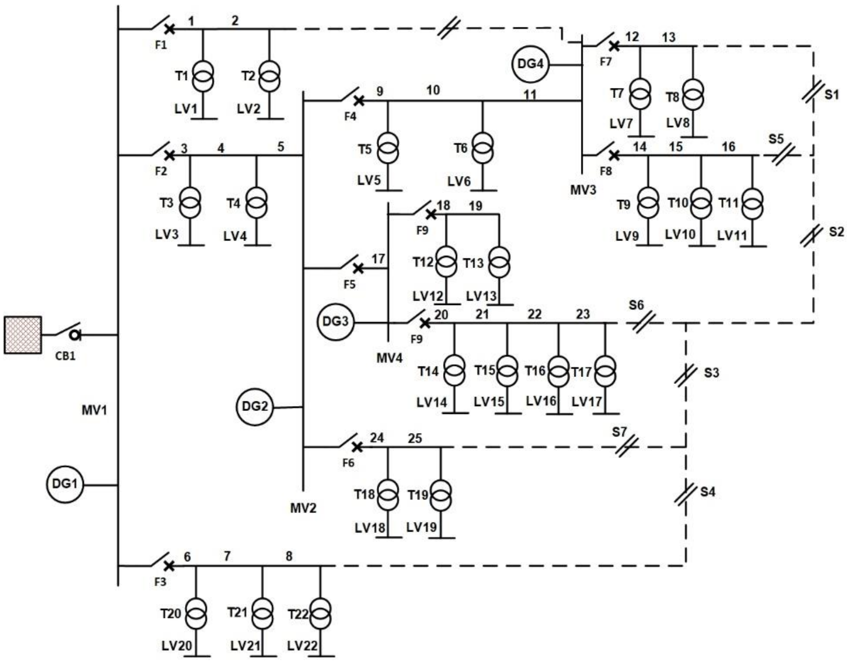


Figure 2: Simplified single-line diagram of Donald network

3.2. Tarnagulla Network

Tarnagulla is located at the end of the incoming feeder (single line diagram of Tarnagulla is given in **Figure 3**. There are no other areas that are being fed via Tarnagulla. Therefore, only Tarnagulla town is modelled for the islanding study. *This model has been considered as the base case for the Tarnagulla network (i.e., business as usual (BAU) case).*

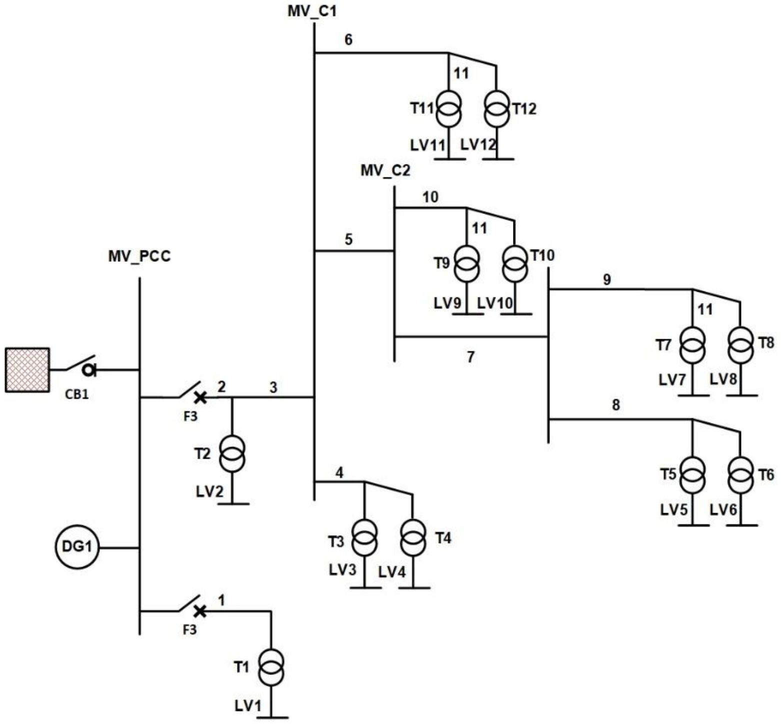


Figure 3: Tarnagulla town connected to the grid

3.3. Stakeholder Identification

According to an international survey of microgrid technology and policy conducted by the Lawrence Berkeley National Laboratory (LBNL) conducted for the Chinese Academy of Sciences – Institute for Electrical Engineers [1], the key drivers for microgrids are apparent across at least four distinct stakeholder groups, with many common threads amongst them. *Energy customers* are increasingly interested in improving their energy efficiency and power quality and reliability (PQR) while lowering costs and environmental footprint. The *electricity supply industry* is concerned about increasing maintaining PQR while serving a growing load and meeting clean energy mandates while lowering costs. *Governments* are driving renewable or clean energy adoption in the interests of safety, energy security, and environmental goals [2]. Additionally, *technology providers* from many diverse sectors, such as information technology and telecommunications, are playing a disruptive role in microgrid development by seeking out innovation opportunities [3].

In this project, our focus will be on the two stakeholder groups: the energy customers with an emphasis on households and business customers of Donald and Tarnagulla, and the government with an emphasis on the regulatory requirements for re-energising and de-energising.

To analyse the impact of microgrids on energy customers, we undertake the analysis of the smart meter data provided by Powercor for the two areas of the Donald and Tarnagulla networks.

Exploratory data analysis (EDA) was first conducted for whole regions for Donald (CTN006) and Tarnagulla (MRO007) for channel E (energy consumption). **Figure 4** shows that there is a quantitative difference in both regions and contestable/non-contestable scale. In Donald, commercial business (40.61%) is the largest energy consumer followed by residential usage (37.58%), whereas in Tarnagulla this order was reversed (commercial business 27.92%, residential usage 48.13%). These differences can be explained by the region size and development level of the town. Donald is larger in area and has more businesses as opposed to Tarnagulla which is more a small town

However, both networks CTN006 and MRO007 contain multiple postcodes.

Thus, in this project we adopt the same assumption made by Projects 49.04 and 49.05 by considering only NMIs associated with postcode 3480 for Donald and postcode 3551 for Tarnagulla. A subsequent analysis was conducted for each of region postcode. **Figure 5** shows that each postcode region has their own pattern due to the characteristics of the customers in each area. Detailed exploratory data analysis found that there are missing data in the original smart meter dataset provided by Powercor (see **Figure 6)**. Therefore, the following data imputation technique was performed based on two rules: (1) select data points 7 days ago from missing point or (2) set missing value as 0 if the data is also missing in 7 days ago. The 1st rule was effective on contestable customers, and 2nd rules are mostly observed from non-contestable customer with low energy demand.

After data imputation, we further analyzed customer profiles' characteristics from season, customer type and energy channel.

- **Seasonal patterns**

Figure 7 and **Figure 8** demonstrated the seasonal difference in Donald and Tarnagulla. Overall, for the year of 2020, the energy consumption is observed to be highest during the winter in both Donald and Tarnagulla. The second highest energy consumption was in the summer of 2020-2021.

- **Customer type**

We observe that domestic farms had similar energy consumption patterns with the energy consumption patterns of residential customers regardless of the region. Subsequently, we grouped domestic farms and residential customers together in our scenario design. For the Donald area (postcode 3480), commercial and residential customers take the largest share of the total energy consumption of the area (see **Figure 7**(g)). This enables us to consider various settings for scenario design to carry out different what-if analyses for the Donald microgrid in terms of load categories. On the other hand, for the Tarnagulla area (postcode 3551), the dominant energy consumption is associated with residential customers (see **Figure 8**(c)). In particular, there are no contestable customers in the Tarnagulla area. Thus, there are very few what-if analysis scenarios for the Tarnagulla area.

- **Smart meter channels (B vs E)**

Figure 9 and **Figure 10** demonstrate that customers with energy generators (e.g., customers with a PV installation) have different load profiles from those without generation capability as they typically consume the energy they generate when it is available (e.g., when PV panels receive sunlight) and only tap into the main grid when they do not generate enough to supply for their energy needs. In general, customers with PV installations commonly have a lower energy load during the daytime.

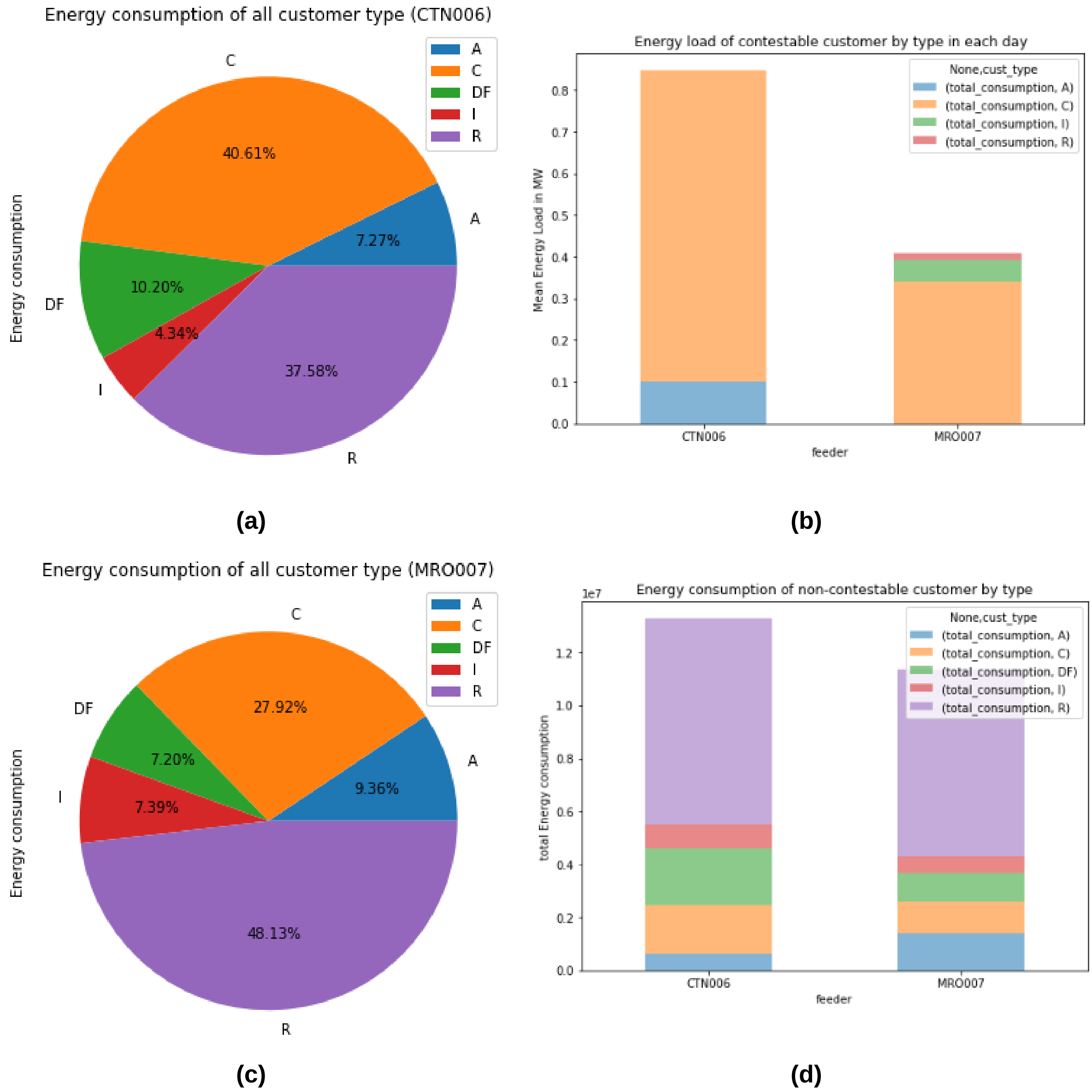
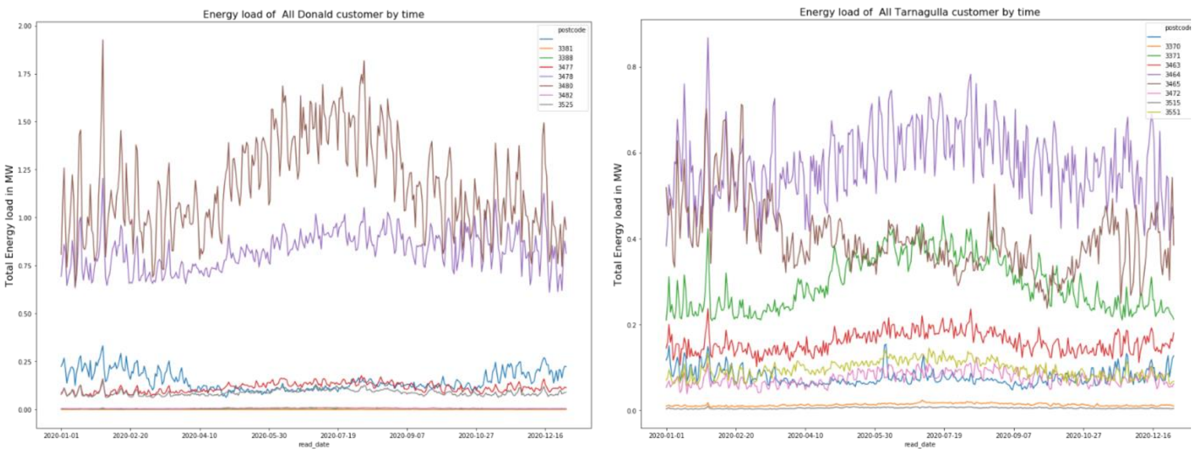
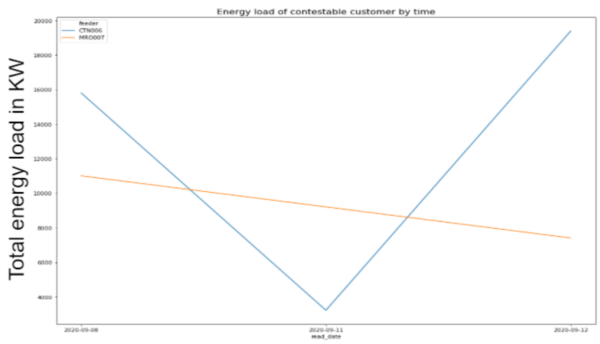


Figure 4: (a) Energy consumption proportion view for CTN006 Donald area separated by customer type, (b) Energy consumption numerical (daily mean load) for CTN006 Donald area separated by customer type, (c) Energy consumption proportion view for MRO007 Tarnagulla area separated by customer type, and (d) Energy consumption numerical view (daily mean load) for MRO007 Tarnagulla area separated by customer type.



(a) (b)

Figure 5: (a) Donald region energy mean load by day separated by postcode, and (b) Tarnagulla region energy mean load by day separated by postcode

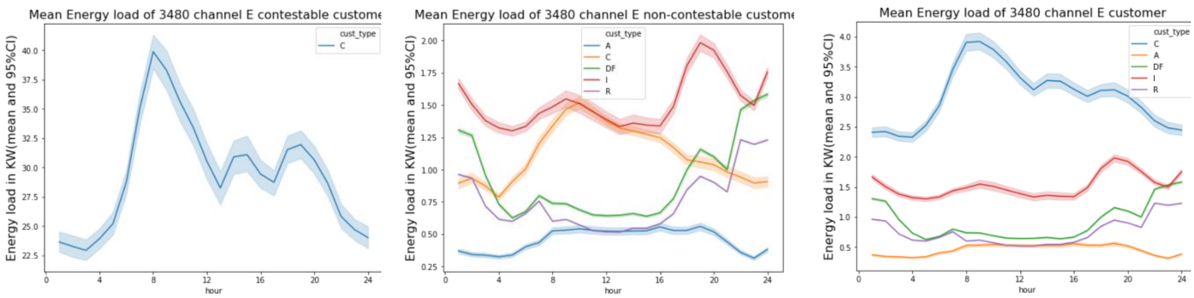



```
analysis_df.groupby(['feeder','read_date']).nunique()
```

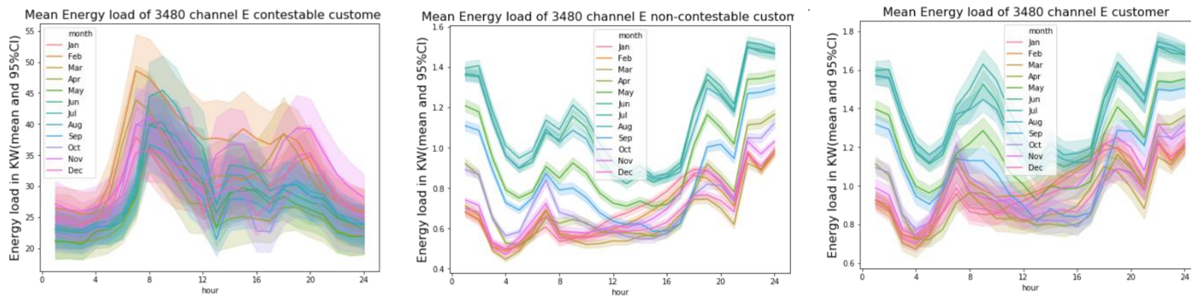
feeder	read_date	feeder	cust_type	nmi	read_date	total_consumption
CTN006	2020-09-08	1	1	25	1	29
	2020-09-11	1	1	2	1	4
	2020-09-12	1	2	35	1	38
MRO007	2020-09-08	1	3	11	1	12
	2020-09-12	1	3	12	1	14

(a) (b)

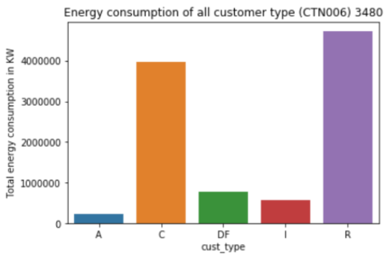
Figure 6: (a) Dramatic decreasing of energy consumption in Donald happened on 11-Sep-2020, and (b) Only two customers have valid recording on 11-Sep-2020.



(a) (b) (c)

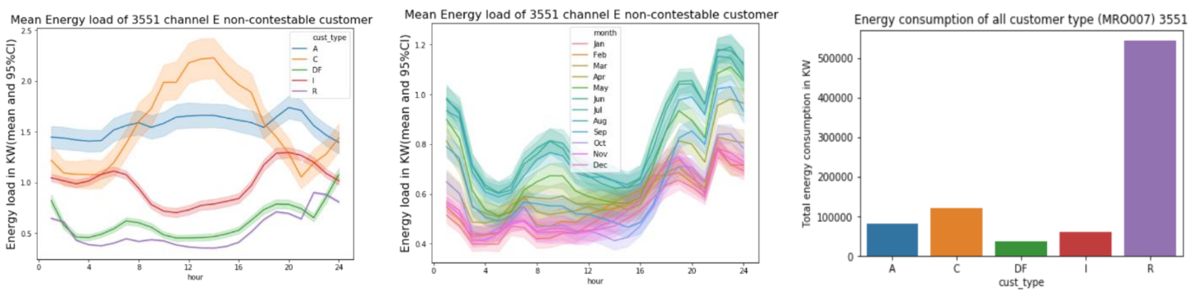


(d) (e) (f)



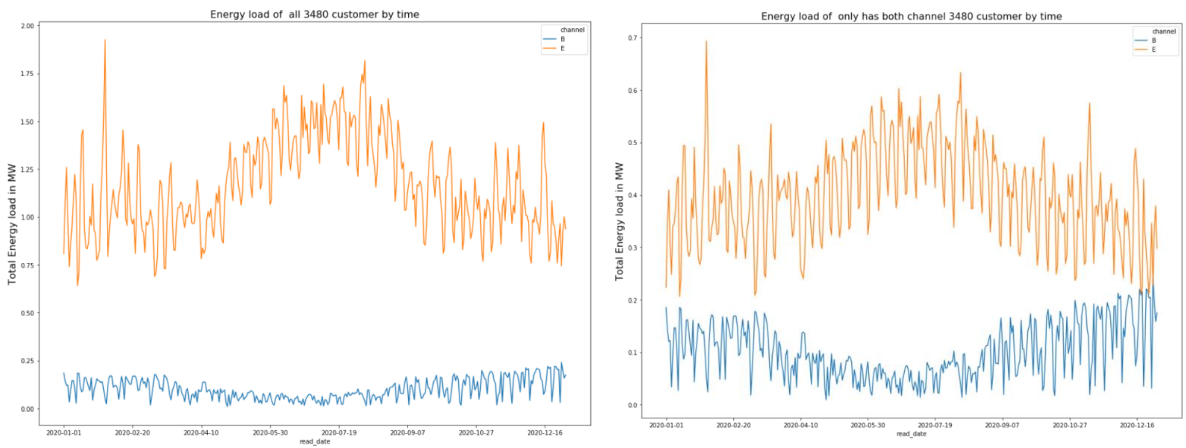
(g)

Figure 7: Donald area: (a) Mean load for contestable customer, (b) Mean load for non-contestable customer, (c) Mean load for all customers, (d) Seasonal mean load for contestable customer, (e) Seasonal mean load for non-contestable customer, (f) Seasonal mean load for all customers, and (g) Total energy consumption by customer type

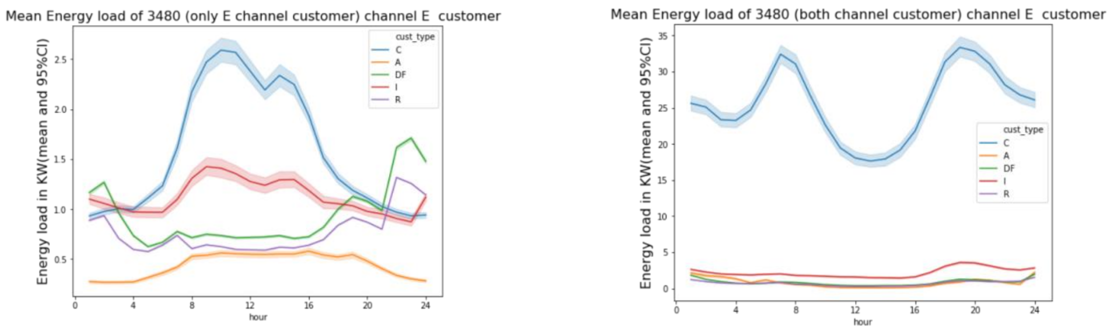


(a) (b) (c)

Figure 8: Tarnagulla area: (a) Mean load for all customers, (b) Seasonal mean load for all customers, and (c) Total energy consumption by customer type

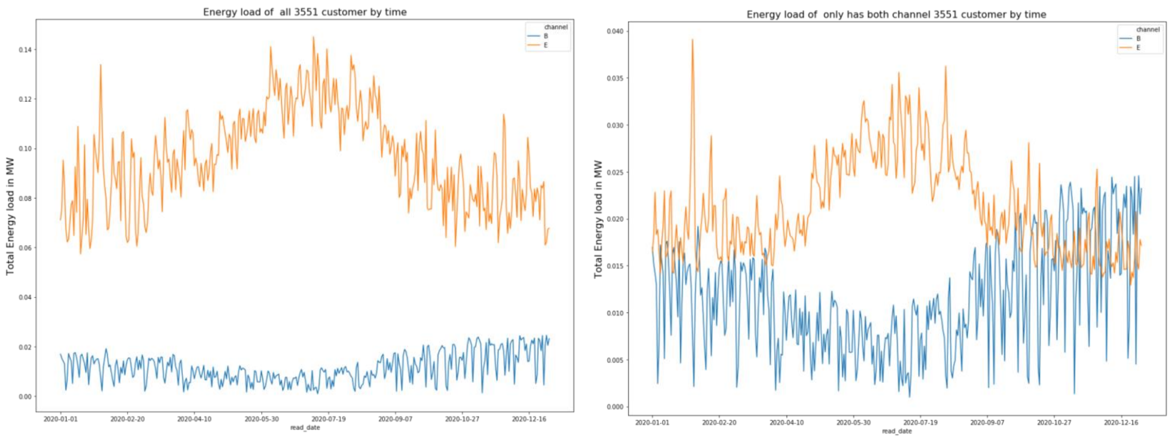


(a) (b)

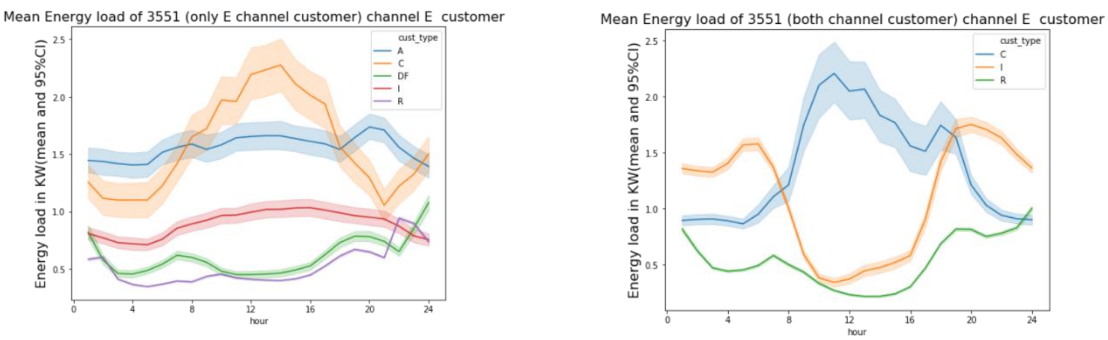


(c) (d)

Figure 9: Donald area: (a) Total energy load per day for all customers, (b) Total energy load per day for customers with PV (channel B), (c) Mean energy load per day for customers without PV, and (d) Mean energy load per day for customers with PV



(a) (b)



(c) (d)

Figure 10: Tarnagulla area: (a) Total energy load per day for all customers, (b) Total energy load per day for customers with PV (channel B), (c) Mean energy load per day for customers without PV, and (d) Mean energy load per day for customers with PV

Based on the analysis of the energy consumption of the customers in the area, we consider different hypothetical scenarios to account for the critical loads, the good-to-have loads and the first-to-cut loads.

Three categories of loads are defined as:

1. **Community critical loads** (referred to as **category 0**, or **Cat. 0**): the energy consumption related to *critical life support* (i.e., hospitals/clinics, aged care facilities, residential households

with life-support requirements), *emergency service providers* (i.e., ambulances, fire and rescue services), *critical infrastructures* (e.g., communication towers, railway services) and possibly other important services such as police and petrol stations.

2. **Medium-flexibility loads** (referred to as **category 1**, or **Cat. 1**): the energy consumption related to *infrastructure whose energy disruption can have a negative impact on the community* (e.g., petrol stations, public administration, schools, postal services, etc.) or can *cause significant economic losses* (e.g., supermarkets/grocery stores) and households whose *residents' wellbeing can be negatively affected by power outages* (e.g. aged people, people who are sensitive to heat/cold).

3. **High-flexibility loads** (referred to as **category 2**, or **Cat. 2**): All remaining loads which are mainly residential customers, as well as some industrial/agriculture customers whose energy disruption will not cause significant economic losses.

In summary, there are 54 potential scenarios for Donald 3480 region given in **Table 1**. Out of 54 scenarios, S1 - S27 are lowest standard critical loads design, and S28 - S54 are highest standard critical loads design. When counting Cat. 0 critical loads, various type of infrastructures, for instance, banks, local supermarkets/groceries, public service premises, petrol stations, pharmacies, emergency services and mobile tower are considered.

Table 1: All potential scenarios for Donald 3480 region

Scenarios	Low standard of critical loads				High standard of critical loads		
	Cat. 0	Cat. 1	Cat. 2		Cat. 0	Cat. 1	Cat. 2
S1	1 hospital, 1 supermarket, 1 accommo-dation building, some life support shops, 5% residential with life support needs	All Domestic Farm, 95% Residential (Same for all Cat. 1) 40% **C**ommercial, 30% **A**griculture, 30% **I**ndustry	All remains	**S28**	1 hospital, 1 supermarket, 1 accommo-dation building, full number of life support shops, services and business, 10% residential with life support needs	All Domestic Farm, 90% Residential (Same for all Cat. 1) 40% **C**ommercial, 30% **A**griculture, 30% **I**ndustry	All remains
S2		40% C, 30% A, 40% I		**S29**		40% C, 30% A, 40% I	
S3		40% C, 30% A, 50% I		**S30**		40% C, 30% A, 50% I	
S4		40% C, 45% A, 30% I		**S31**		40% C, 45% A, 30% I	
S5		40% C, 45% A, 40% I		**S32**		40% C, 45% A, 40% I	
S6		40% C, 45% A, 50% I		**S33**		40% C, 45% A, 50% I	
S7		40% C, 60% A, 30% I		**S34**		40% C, 60% A, 30% I	
S8		40% C, 60% A, 40% I		**S35**		40% C, 60% A, 40% I	
S9		40% C, 60% A, 50% I		**S36**		40% C, 60% A, 50% I	
S10		55% C, 30% A, 30% I		**S37**		55% C, 30% A, 30% I	
S11		55% C, 30% A, 40% I		**S38**		55% C, 30% A, 40% I	
S12		55% C, 30% A, 50% I		**S39**		55% C, 30% A, 50% I	
S13		55% C, 45% A, 30% I		**S40**		55% C, 45% A, 30% I	
S14		55% C, 45% A, 40% I		**S41**		55% C, 45% A, 40% I	
S15		55% C, 45% A, 50% I		**S42**		55% C, 45% A, 50% I	
S16		55% C, 60% A, 30% I		**S43**		55% C, 60% A, 30% I	
S17		55% C, 60% A, 40% I		**S44**		55% C, 60% A, 40% I	
S18		55% C, 60% A, 50% I		**S45**		55% C, 60% A, 50% I	
S19		70% C, 30% A, 30% I		**S46**		70% C, 30% A, 30% I	
S20		70% C, 30% A, 40% I		**S47**		70% C, 30% A, 40% I	
S21		70% C, 30% A, 50% I		**S48**		70% C, 30% A, 50% I	
S22		70% C, 45% A, 30% I		**S49**		70% C, 45% A, 30% I	
S23		70% C, 45% A, 40% I		**S50**		70% C, 45% A, 40% I	
S24		70% C, 45% A, 50% I		**S51**		70% C, 45% A, 50% I	
S25		70% C, 60% A, 30% I		**S52**		70% C, 60% A, 30% I	
S26		70% C, 60% A, 40% I		**S53**		70% C, 60% A, 40% I	
S27		70% C, 60% A, 50% I		**S54**		70% C, 60% A, 50% I	

For Tarnagulla, there were only 4 potential scenarios designed given in **Table 2**. It can be observed that the region associated with postcode 3551 get various type of services from 3550 region which is the regional center, thus most businesses and commercial/industrial customers are mainly located in 3550. Thus, most customers in 3551 are residential. Due to this situation, the critical loads design is fewer in number. Furthermore, the total load in 3551 is considerably smaller. Thus, we only considered several scenarios that give noticeable load differences.

Table 2: All possible scenarios for Tarnagulla 3551 region

Scenarios	Low standard of critical loads				High standard of critical loads		
	Cat. 0	Cat. 1	Cat. 2		Cat. 0	Cat. 1	Cat. 2
S1	some life support shops, 5% residential with life support needs	All Domestic Farm, 95% Residential (Same for all Cat. 1) 40% **C**ommercial, 30% **A**griculture, 30% **I**ndustry	All remains	**S3**	full number of life support shops, services and business, 10% residential with life support needs	All Domestic Farm, 90% Residential (Same for all Cat. 1) 40% **C**ommercial, 30% **A**griculture, 30% **I**ndustry	All remains
S2		70% C, 60% A, 50% I		**S4**		70% C, 60% A, 50% I	

For each of the above scenarios, we generate the optimal system designs with detailed cost analyses (based on the HOMER software) as well as conduct reliability and steady-state performance assessment in DIgSILENT PowerFactory (see **Section 5** below).

4. Fundamental concepts and overall methodologies

This section presents the fundamental concepts (including definitions of microgrid) and outline the methodologies employed by the researchers when conducting technical analyses into techno-economic designs and reliability assessment of microgrids.

4.1. Definitions of Microgrid

Today, the microgrid concept has no unique definition since modern microgrids are not standardised in design but tailored to a specific location and to local requirements [3], [1]. Subsequently, we looked at how the microgrid concepts have been defined, especially by authorities at different levels of governments in Australia and elsewhere.

Definition 1 (**U.S. Department of Energy (DOE)**): "*A microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode. A remote microgrid is a variation of a microgrid that operates in islanded conditions.*"

U.S. Department of Energy Electricity Grid Research and Development [25]

Definition 2 (**The International Council on Large Electrical Systems (CIGRE)**): "*Microgrids are electricity distribution systems containing loads and distributed energy resources (such as distributed generators, storage devices, or controllable loads,) that can be operated in a controlled, coordinated way either while connected to the main power network or while islanded*."

The International Council on Large Electrical Systems (CIGRE) [26]

Definition 3 (**Victoria State Government**): "*A microgrid generally operates while connected to the grid however, importantly it can break off and operate on its own using local energy generation. It has a single point of connection with the grid with a monitoring and control platform used to coordinate the supply and demand of the customers connected to the microgrid*."

Department of Environment, Land, Water and Planning (DELWP) of the Victoria State Government [18]

Definition 4 (**AEMC**): [see also **Figure 11**] "*An electricity supply arrangement that is not physically connected (directly or indirectly) to the national grid can be referred to as a stand-alone power system (SAPS). Microgrids and individual power systems are both a form of stand-alone power system.*

Microgrid
A microgrid is a SAPS that generates and supplies electricity to multiple customers. This could include anything from a large town to two farms connected to each other. Power may be supplied by a mix of local generation and storage, possibly combined with behind-the-meter generation and storage. Remote communities, island resorts and remote mining towns are often supplied by microgrids.

Individual power system
An individual power system (IPS) is a SAPS that generates and supplies electricity to a single customer. Typically, power is generated by a combination of renewable generation, energy storage and/or conventional diesel generators.

Embedded network

Microgrids and individual power systems are distinct from embedded networks. While embedded networks supply electricity to customers in a way that is an alternative to standard supply, they remain connected to the national grid (they may or may not have generation within the embedded network). The regulatory framework for embedded networks is being considered in a concurrent review by the AEMC."

Australian Energy Market Commission (AEMC) website [19]

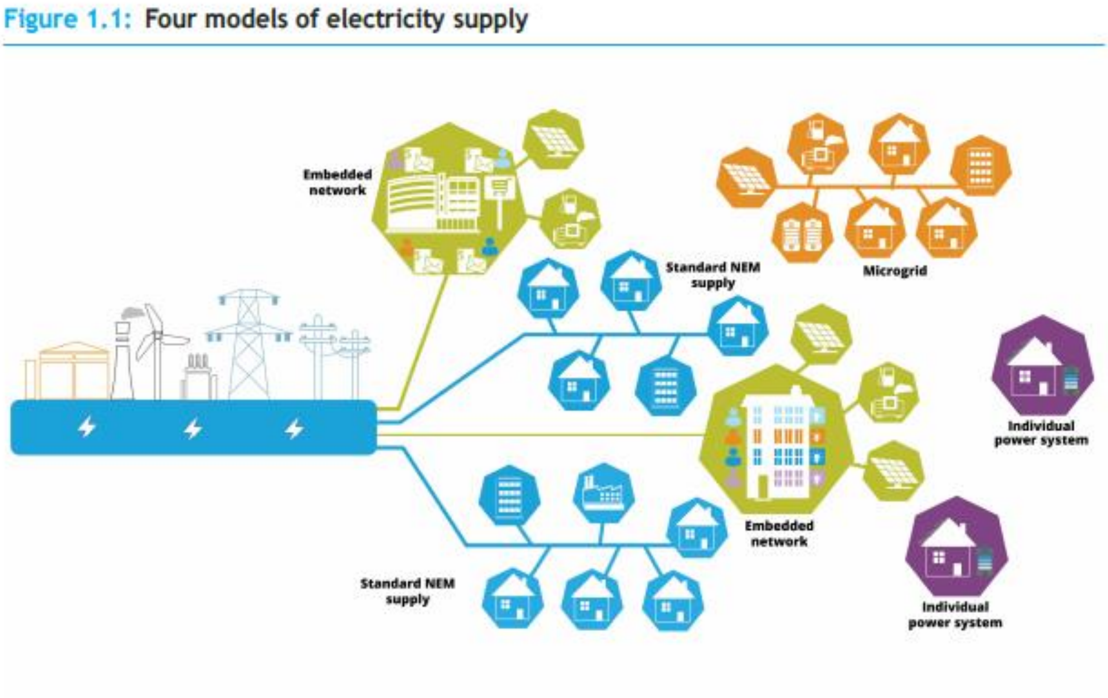


Figure 11: Different models of electricity supply (reproduced from [19])

There are a few reasons for us to present the above definitions. First, there are major differences between the Victoria government's definition of microgrids which clearly include grid-connected power systems and the AEMC's definition of microgrids which classifies microgrids as stand-alone power systems. These differences are important as an AEMS's review of the regulatory frameworks for microgrids was included in their ***Review of the regulatory frameworks for stand-alone power systems*** [19] and there were almost no mentions of the regulatory requirements regarding re-energisation and de-energisation. Second, according to the AEMC's definition of embedded systems, the embedded systems share most characteristics with a grid-connected microgrid except for the ability to operate in islanded conditions. Subsequently, it is important to take into consideration the AEMC's ***Review of regulatory arrangements for embedded networks*** [33] as well as its more recently updated documents. As this feasibility study is conducted for the regional towns Donald and Tarnagulla in Victoria, we will adopt the definition of microgrids found on the Victoria government website which happen to be consistent with the definitions by the US Department of Energy (DOE) and the International Council on Large Electrical Systems (CIGRE) (see **Definition 1** and **Definition 2**). This allows us to refer also to various international technical standards and requirements for interconnection of microgrids and distributed energy resources (DERs) such as those proposed by the IEEE and the IEC.

4.2. Methodology: Techno-Economic Design

In this project, the techno-economic design is mainly performed through HOMER Pro platform for which the provided data from Powercor are fed into the platform to design an economic system for both Donald and Tarnagulla areas. For this aim, both contestable with the resolution of 15 minutes and non-contestable data with the resolution of 30 minutes are processed through appropriate data analytics, in which these data are fed through HOMER Pro to find the optimum values for the integrated microgrid. Detailed analysis will be provided in the next sections.

4.3. Methodology: Reliability Assessment

The reliability assessment is one of the important issues to design a reliable and stable power system, especially for islanded microgrids. The reliability assessment is mainly performed and carried out from two aspects which are security and generation adequacy. **Figure 12** indicates the details of reliability assessment in DIgSILENT Power Factory platform. In order to assess the reliability of the system, it is required to provide two indispensable analyses in terms of security and generation adequacy [4]. It is worth to note that the power system has mainly two basic factors, which make the system unreliable. The first factor is happened due to different failures in busbars, transforms, and transmission/distribution lines. However, the uncertainty characteristics of the generation units are not considered in this analysis. Therefore, the second factor, which mainly comes out from the uncertainty features of the generation units, needs to be considered. For this aim, it is crucial to investigate the behaviour of the islanded microgrids through the generation adequacy analysis, which particularly considers the different unpredictable uncertainties of generation units via complex mathematical methods. In the following subsection, the different indices are introduced by focusing on different failures and generation uncertainties.

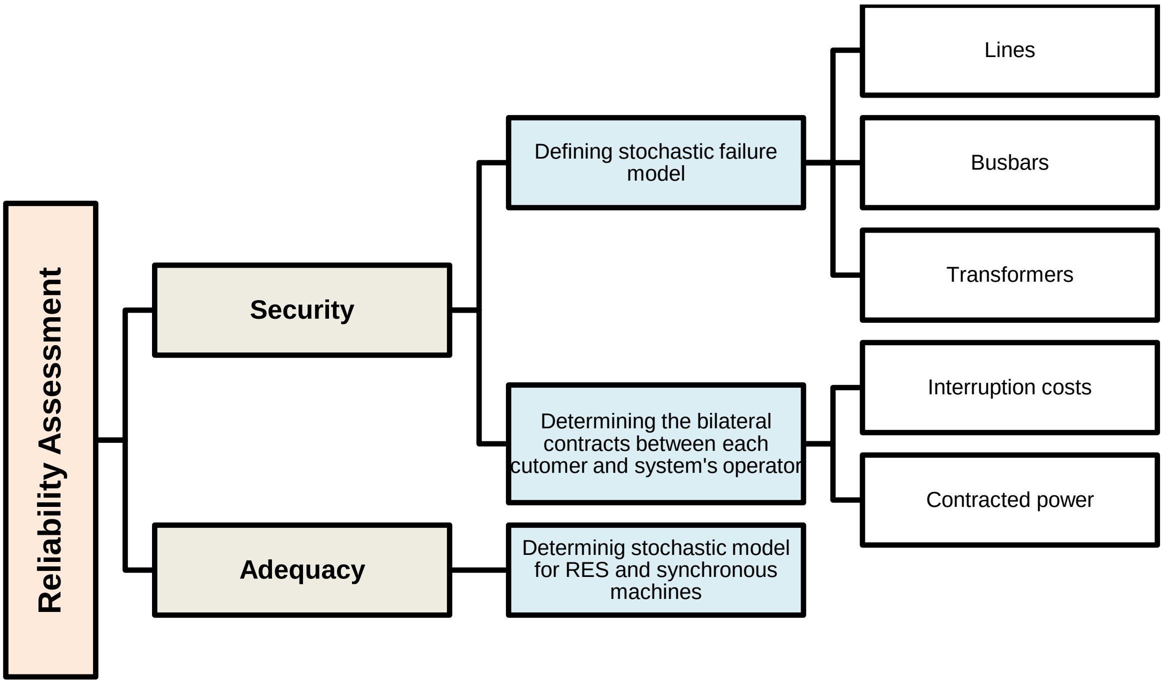


Figure 12: The reliability assessment process

Table 3 provides a comparison between this project and other projects in terms of reliability assessment techniques. The detailed explanations about **Table 3** are expressed as follows and the complete comparisons between this project and projects 49.04 and 49.05 are provided for more clarifications:

- **Considering prices in proportion with the rating power:** In order to accurately design the microgrids in Donald and Tarnagulla in terms of techno-economic analysis in HOMER Pro, the equipment prices are imported in proportion with the rating power (see **Figure 13**). In projects 49.04 and 49.05, a high-level view of the network has been taken with projection on price at a higher price range of the equipment and technologies to be installed for the microgrids. In this project (project 49.06), we have gone one step further by looking into more details in terms of pricing by looking at some references in the Australian market (see references **[8],[9],** and **[10])** so that prices of the equipment to be installed will be in proportion with the rating of the equipment.

- **Integration of energy resources:** Similar to the consideration in the previous point, while projects 49.04 and 49.05 have done high-level techno-economic and reliability analyses to investigate the trade-off between costs and power reliability, this project (49.06) has also gone a step deeper into the analyses across three different criteria to be considered: costs, power quality and reliability and sustainability as we try to answer an important question to be asked by a stakeholder regarding the impact a specific energy resource or technology (such as battery, PV, and diesel gensets) will have. For instance, if a utility grid outage will last for more than 24 hours then it is clear that the microgrid will not generate any energy at night unless diesel gensets will be operated. In this report, we show the results for all combinations with PV technology even though we conducted also the analysis for the configurations without PV technology (i.e. DGs only and DGs/Battery only) and obtained the relevant results. As discussed below, we have also gone one step further by addressing the generation adequacy of the proposed microgrid design and sizing.

- **GPS coordinates in DIgSILENT:** In DIgSILENT Power Factory, the GPS coordinates need to be taken into consideration in order to allocate capacities for PVs. As we know, the weather's condition is different in different locations, therefore, it is crucial to consider this point for accurate design of PV panel numbers as well as the required inverters in each area. In this project, we follow the recommendation from DIgSILENT developers (see the book: **Advanced Smart Grid Functionalities Based on PowerFactory**, edited by Francisco Gonzalez-Longatt, José Luis Rueda Torres, Springer 2018).

- **Real load characteristic:** As the nature of the loads is variable, therefore, it is very important to be considered in both platforms including HOMER Pro and DIgSILENT Power Factory. In projects 49.04 and 49.05, the loads are considered as fixed loads for reliability analysis in DIgSILENT based on snapshots of the load data (extracted from the smart meter dataset). In this project (49.06), we again have advanced this analysis further by analysing and simulating load data as time series. Therefore, we enable the computation of reliability indexes for different months based on the hourly load data (extracted from the smart meter dataset provided by Powercor).

- **Failure on equipment:** In reliability analysis, in order to investigate the worst-case condition in microgrids' networks in Donald and Tarnagulla area, this project include failure on every equipment instead of generalizing the failure of the entire area. Thus, we enable the worst-case failure studies.

- **Common mode failure:** In order to be more accurate in reliability analysis, it is important to consider the common-mode failures which is mainly for PV panels, inverters, batteries, and DGs. This project (49.06) adds these different types of failure to the analysis to guarantee more accurate results.

- **Load point interruptions:** In reliability analysis especially in islanded microgrids in Donald and Tarnagulla, the interruptions in different busbars are also important to be considered. Therefore, calculating the reliability indexes based on average value across the entire microgrid may not accurately reflect the differences in the reliability of different feeders of the microgrid. Thus, this project (49.06) provides detailed results for each load point when performing power quality and reliability analysis.

- **Generation adequacy evaluation**: As explained above, the system design and reliability assessment need to be conducted based on the studied area for which the GPS coordinates will be very crucial to design the system especially to calculate the generation's capacity as well as the suitability of different integrations of technologies. In addition, the GPS coordinate data is essential for accurate analysis in software tools (such as DIgSILENT) as the real load characteristics are needed for evaluating the balance between generation and consumption in the presence of load characteristics. Furthermore, the existing uncertainties in generation units including PVs, batteries, and DGs need to be conducted through generation adequacy evaluation by considering the availability and outages.

Table 3: An overall comparison among different projects

Equipment	Project 49.04	Project 49.05	This project
Considering prices in proportion with the rating power	×	×	✓
Integration of energy resources	×	×	✓
GPS coordinates in DIgSILENT	×	×	✓
Real load characteristic	×	×	✓
Failure on equipment	Specific lines	Partially	All Equipment
Common mode failure	DERs ignored	DERs ignored	DERs included
Load point interruptions	×	×	✓
Generation adequacy evaluation	×	×	✓

4.3.1. Security Assessment:

In this subsection, different indices for reliability assessment are presented in which the interruption indices for each load point are firstly introduced while the reliability indices for the entire loads are presented by using the load point indices [5] and the detailed formulation can be found in Appendix C.

4.3.2. Generation Adequacy:

The behaviour of the power system as well as microgrids is completely a probability issue as there are always so many uncertainties in the system in terms of both generation and consumption. As it is so obvious, the characteristics of the loads are uncertain as long as there are so many uncertainties in the generation units such as lower fuel in diesel generators and irradiation/temperature uncertainties in solar systems [7]. Therefore, an appropriate method based on probability is mandatory to estimate the behaviour and reliability of the power system in the presence of these uncertainties for which one of the most important and effective strategies for exploring the reliability of the system in terms of providing energy to the loads (particularly in the islanded microgrids) is the generation adequacy analysis. Basically, the generation adequacy analysis is based on Monte-Carlo method, and it is worth to note that the mathematical and detailed analysis of this method is out of the focus of this project. However, this analysis is carried out through DIgSILENT Power Factory platform in order to investigate the reliability of the Donald and Tarnagulla networks in islanded operation mode. In this analysis, there are two important indices, which are vital to be taken into consideration and the following subsections present these factors and the detailed analysis can be found in Appendix D.

4.4. Methodology: Customer's flexibility

The high-level approach adopted in this project to investigate the flexibility a customer can have regarding the supply security for the different loads in their household or at their business can be summarised as follows:

1. Based on the mathematical model for a market-based mechanism proposed by Li et al [13], we develop a market platform for microgrids. Based on the developed platform, we aim to investigate the potential impact of a demand response (DR) program on the customers. As demonstrated in this report, the developed platform provides a tool for what-if analyses by simulating varying microgrid designs and mapping such a design to an energy cost function, varying customers' load profiles and varying customers' preferences/utility functions. For each such scenario, the impact of a specific microgrid design/sizing on the customers' objective functions in the presence of demand response can be studied. **That is, this can be a tool to be used by power companies or consultants to provide customers and other stakeholders with comprehensive analysis of the impact of not having a specific load supplied during islanding of the microgrid (by translating such an impact to economic losses/gains).**

2. To demonstrate the what-if analysis using our developed platform in the context of a microgrid operated in the islanded mode, we have simulated a specific scenario in which the energy cost function that captures the relation between different types of generation capabilities (e.g., PV is considered to have a very low cost but can only supply up to a certain capacity, after that the excess loads have to be met by diesel genset units at a much higher cost). Due to a range of issues, we are unable to obtain a real-world appliance model from the two areas (Donald and Tarnagulla), nor are we able to obtain the customers' preferences/utility functions associated with each NMI. Subsequently, we have also simulated a comprehensive appliance model for the hypothetical customers of the microgrid and made some assumptions around their preferences to simulate a utility function for each customer. The simulated appliance model covers a comprehensive range of appliances including: temperature-based appliances (such as air conditioner and refrigerator), deadline-based appliances whose usage can be shifted within a time window as long as their usage can be done before their respective deadlines (such as electrical vehicles, dish washer, clothes washer), time-based appliances whose usage is required at the time the customer needs them (such as lighting) and also time-and-usage-based appliances (such as computers, entertainment units – TVs, audio speakers).

3. Based on the aforementioned what-if scenario, we have conducted a detailed analysis to demonstrate the impact of demand response (realised via the dynamic pricing in the developed market platform) on the loads in the microgrid. In particular, there is a clear peak-load flatten

when dynamic pricing has been applied. An important observation from this analysis is that: Not all loads are equal. Some loads can be shedded and some loads can be shifted to a different time for the purpose of flattening the overall peak load for the purpose of cost saving. Therefore, careful analyses can be conducted to provide insights into the following: (i) *what is the flexibility a customer can have regarding the supply security for the different loads in their household or at their business (by translating such a flexibility to monetary cost associated to not having those loads supplied)*? and (ii) *if certain constraints are in place for the microgrid generation capacity, what would be the impacts of such constraints on a specific customer (especially business customers) for their loads not being supplied*? However, to conduct such an analysis, we will need the data about the customers' energy consumptions and their preferences on the consumption of different loads within their household/business. Due to a range of issues, the information is not available to enable a more accurate analysis for customers in Donald and Tarnagulla.

4.5. Methodology: Regulatory requirements

The investigation into regulatory requirements related to de-energisation and re-energisation of both the microgrid and its loads/generation units has been broken down to several sub-tasks:

1. Review of existing regulations at different levels of governments (state and federal)
2. Review of existing regulatory frameworks that have been established elsewhere and identify the relevant parts from such framework in the context of community microgrids in Victoria, Australia.
3. Review of international technical standards and requirements for interconnection of microgrids and distributed energy resources (DERs) including those proposed by the IEEE and the IEC.
4. Provide recommendations for regulatory requirements regarding de-energisation and re-energisation for the microgrid and its loads.

5. TASK 1: Techno-economic analysis and power quality and reliability assessment

5.1. Parametrization and Key Indices

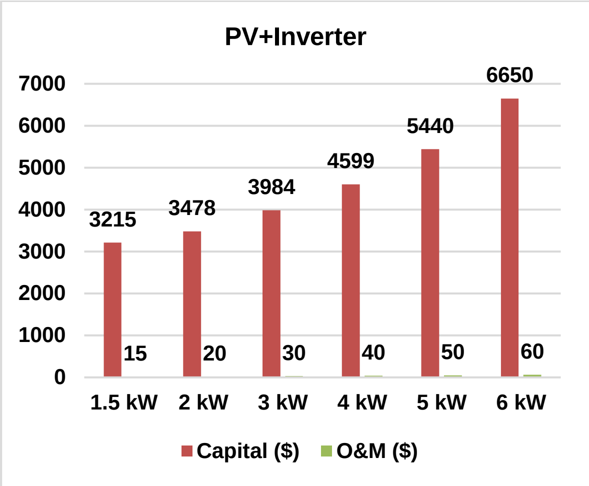
This section contains a detailed description of the proposed microgrid economic and cost estimation framework and corresponding results.

5.1.1. Donald Network: Techno-Economic Analysis

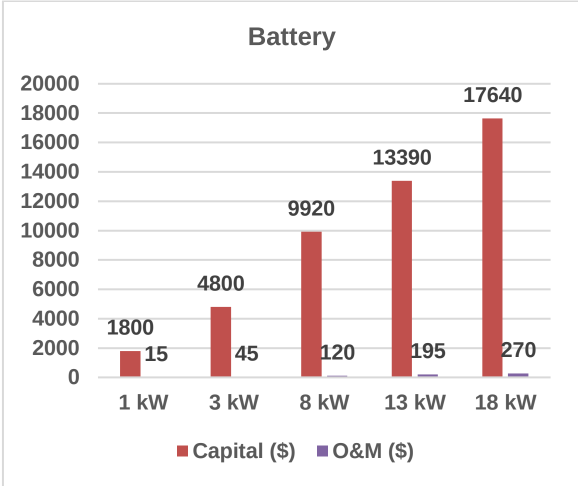
This section provides a detailed explanation of the design for Donald area. For this aim, the smart meter data is input to the HOMER Pro software for which the parameters are listed in **Table 4** as well as the capital costs along with the O&M costs are illustrated in **Figure 13**. It is worth noting that the provided costs included the cost of equipment and the installation costs as well. In the designed system, the cost of utilized converters is included in PVs while the required converter's capacity for batteries is calculated separately whenever a battery is included in the configuration. Therefore, the capacities of inverters required for PV panels are chosen based on the installed PV panels. In this design, it is worth noting that 4 diesel generators are also used based on the capacity of the entire loads for which the numbers and capacities of these DGs are chosen by considering the main configuration of Donald network. In order to conduct this analysis, Donald network has 4 main medium voltage busbars; therefore, the number of DGs is selected 4 in order to consider the worst possible circumstances in the system which will be explained later on in detail during the reliability analysis. For economic results, in project 49.05, the prices of the equipment have assumed fixed values, but it is not fixed in the real market and can vary in proportion with the rating power. The results of this project are more accurate than project 49.05. In this project, we have used the data from **Figure 13** as inputs for the prices. By considering these explanations, the configuration of the Donald network designed in HOMER Pro is shown in **Figure 14Error! Reference source not found.**. By importing all these data in HOMER Pro, a techno-economic analysis is calculated for which the summary of the design for Donald area along with the different scenarios are illustrated in Appendix A (i.e. **Table 44** to **Table 48**).

Table 4: The used elements in HOMER Pro for Donald area

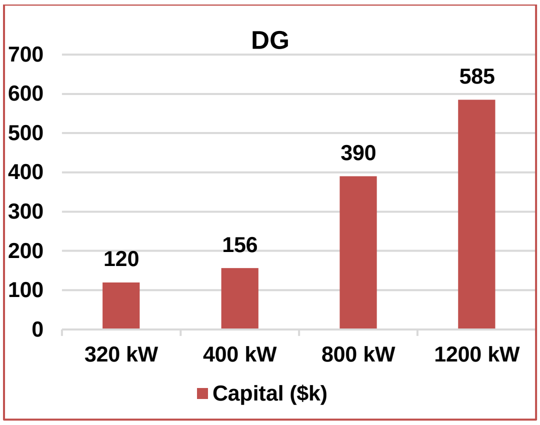
Solar PVs: Name: **LONGi Solar LR6-72BK;** Panel Type: **Flat plate;** Rated Capacity: **370 W;** Temperature Coefficient: **-0.41;** Operating Temperature: **47 ºC;** Efficiency: **17.8%**
Batteries: Name: **Idealized Battery Model;** Nominal Voltage: **6 V;** Nominal Capacity: **1 kWh;** Nominal Capacity: **167 Ah;** Roundtrip Efficiency: **90%;** Max Charge Current: **167 A;** Max Discharge Current: **500 A**
Converter: Name: **Generic system converter** ***Note:*** *The size of the converter is determined based on the installed solar-battery system.*
Diesel Generators: Name: **CAT-50 Hz-PP;** Rating power: **1500 kVA, 1000 kVA, 500 kVA, 400 kVA**



(a) PV panel + Inverter [8]



(b) Battery [9]



(c) Diesel generator [10]

Figure 13: The price of equipment based on capacities

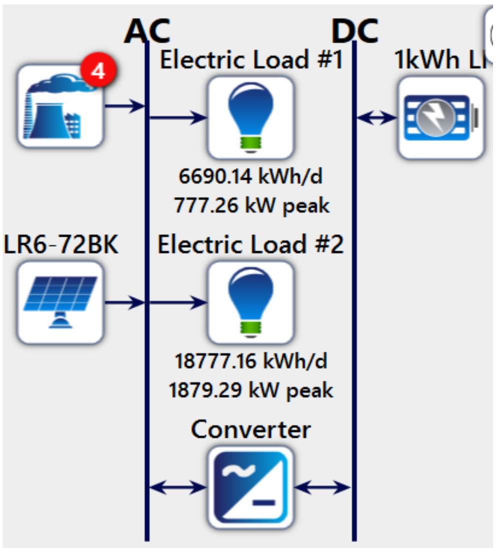


Figure 14: The HOMER model of Donald network

5.1.2. Donald Network: System Design in DIgSILENT

Figure 2 indicates the configuration of Donald network, which will be used in our design, and the parameters of the network is summarised as follows. Here, the real network is shown with lines while the dashed lines are proposed and added to the network for possible reconfiguration of the grid. Regarding the reconfiguration of the network, it is important to note that the modern microgrids' infrastructures are mainly controlled by wireless communication; therefore, the reconfiguration topologies are also analysed incorporating with different scenarios to investigate the flexibility of the system. In the presented structure in **Figure 2**, the nominal values of the system are presented as follows:

A. Diesel Generators

DG1: 1500 kVA, **DG2:** 1000 kVA, **DG3:** 500 kVA, **DG4:** 400 kVA

B. Transformers

Note: All transformers are 22/0.433 kV, and the presented rating power is based on kVA.

T1: 63, **T2:** 5×25, **T3:** 50, **T4**: 200, **T5:** 25, **T6:** 315, **T7:** (200+25), **T8:** 200, **T9:** (200+25), **T10:** 3×63, **T11:** 200, **T12:** 25, **T13:** 100, **T14:** 318, **T15:** 4×200, **T16:** 2×63, T17: 200, **T18:** 2×25, **T19:** 2×25, **T20:** 25, **T21:** 100, **T22:** 25

C. Loads

All time-series loads are distributed based on the rating power of each transformer.

D. PVs

Note 1: The PV panels are installed in the following busbars:

MV_PCC, MV_C3, MV_C1, MV1, MV3, MV5, MV7, MV9, MV12, MV14, MV18, MV20

Note 2: The detailed calculations are also provided.

- ***PV Panels Data:*** *Each PV panel has the following rating characteristics:*

MPP Power: 0.37 kW

MPP Voltage: 60 V

MPP Current: 6 A

Open Circuit Voltage: 70 V

Short Circuit Current: 7 A

- ***Installed capacity in each busbar:*** *Based on calculation, the number of utilized inverters along with the number of PV panels are provided as follows by considering the GPS coordination of Donald area:*

Number of parallel inverters (each busbar): 54

Total number of inverters: 12×54=648

Number of panels per inverter: 15

Apparent Power (Inverter OR 15 numbers of panels): 5.55 kW

E. Batteries

<u>Note 1:</u> The batteries are installed in the following busbars:

MV_PCC, MV_C3, MV_C1, MV1, MV5, MV7, MV9, MV12, MV14, MV18, MV20

Parallel Units: 54

Rating Power: 1.35 kW

It is worth to note that the Donald coordinates are as 36.3694° S, 142.9820° E (UTC+10:00), and the numbers of PV panels and required inverters are calculated by considering the determined optimum capacity from HOMER Pro. According to the summarized results in **Table 44**, the required capacity for PVs integrated with the batteries and DGs with the renewable fraction of 27.2% is almost 3600 kW. Therefore, the number of PV panels is determined as follows by choosing a 370 W PV panel as follows:

$$Number\ of\ PV\ Panels\ = \frac{Optimum\ Capacity\ from\ HOMER}{PV\ Panel\ Rating\ Power\ at\ MPP} = \frac{3600}{0.37} = 9730 \tag{19}$$

In **Figure 2**, as early indicated, 12 medium-voltage busbars are selected for installing PV panels and the common installed capacity for each household is with considering 27.2% renewable fraction in Donald area as follows:

$$15\ Panel\ \times 0.37\ kW = 5.5\ kW \tag{20}$$

In equation (20), the number of PV panels that connect to each inverter is 15. By considering these calculations, the total number of inverters, which is installed in the entire system, is determined as follows:

$$Total\ number\ of\ inverters = \frac{9730\ Panel}{15\ Panel/Inverter} = 649\ Inverter \tag{21}$$

As the number of busbars, which selected for installing PV inverters is 12, therefore, the number of parallel inverters, installed in each busbar, is calculated as follows:

$$\frac{649\ Inverter}{12} = 54\ Parallel\ Inverter/Busbar \tag{22}$$

It is important noting that the calculations are done based on residential customers, for which each householder normally uses 5.5 kW solar system. However, there are other customers are existed in the system, such as commercial customers. In that case, the required capacity is allocated in proportion with their requirements, in which it is mainly based on the size of industry that each customer uses. Overall, the capacities can be easily determined and deducted from these calculations.

5.1.3. Tarnagulla Network: Techno-Economic Analysis

In order to design the required capacities for the Tarnagulla area, a similar manner as Donald network is used for which a summary of the results is demonstrated as **Table 50** to **Table 53**.

Table 5: The used elements in HOMER Pro for Tarnagulla area

Solar PVs: Name: **LONGi Solar LR6-72BK;** Panel Type: **Flat plate;** Rated Capacity: **370 W;** Temperature Coefficient: **-0.41;** Operating Temperature: **47 ºC;** Efficiency: **17.8%**
Batteries:

Name: **Idealized Battery Model;** Nominal Voltage: **6 V;** Nominal Capacity: **1 kWh;** Nominal Capacity: **167 Ah;** Roundtrip Efficiency: **90%;** Max Charge Current: **167 A;** Max Discharge Current: **500 A**
Converter: Name: **Generic system converter** ***Note:*** *The size of the converter is determined based on the installed solar-battery system.*
Diesel Generators: Name: **CAT-50 Hz-PP;** Rating power: **400 kVA**

F. Diesel Generators

DG1: 400 kVA

G. Transformers

Note: All transformers are 22/0.433 kV, and the presented rating power is based on kVA.

T1: 50, **T2:** 63, **T3:** 2×50, **T4**: 2×25, **T5:** 50, **T6:** 50, **T7:** (2×25), **T8:** 2×25, **T9:** 50, **T10:** 2×25, **T11:** 2×25, **T12:** 50,

H. Loads

All time-series loads are distributed based on the rating power of each transformer.

I. PVs

Note 1: The PV panels are installed in the following busbars:

MV_PCC, MV_C1, MV_C2, MV_C3

Note 2: The detailed calculations are also provided.

- ***PV Panels Data:*** *Each PV panel has the following rating characteristics:*

MPP Power: 0.37 kW

MPP Voltage: 60 V

MPP Current: 6 A

Open Circuit Voltage: 70 V

Short Circuit Current: 7 A

- ***Installed capacity busbars:*** *Based on calculation, the number of utilized inverters along with the number of PV panels are provided as follows by considering the GPS coordination of Donald area:*

Number of parallel inverters (each busbar): 18

Total number of inverters: 4×18=72

Number of panels per inverter: 15

Apparent Power (Inverter OR 15 numbers of panels): 5.55 kW

Power Factor: 0.8

J. Batteries

<u>Note 1:</u> The batteries are installed in the following busbars:

MV_PCC, MV_C1, MV_C2, MV_C3

Parallel Units: 18 (Each busbar)

Rating Power: 1.35 kW

5.2. Comparisons to the settings used in Projects 49.05

By importing the data in HOMER Pro, the designed capacities along with the different criteria are summarised in **Table 44** for the Donald area. As can be seen from **Table 44**, the most affordable and optimal configuration which is designed is the integration of PV, batteries, and DGs for which the COE is the list as equal to $0.323/kWh by participating 27.2% of renewable penetration.

Table 6 shows a comparison between the designed system in this project and project 49.05 from where it can be seen that the penetration of the renewable energies in the current project is 27.2% while it is 17% for the project 49.05. So, the policy of CO2 emission is less satisfied in project 49.05. In addition, the COE is $0.323/kWh in this project while it is $0.375/kWh in project 49.05. The NPC in project 49.05 is lesser than the current project as it is used the lesser renewable fraction and in fact, the NPC in project 49.05 is much higher than the current project if they use higher fraction of renewables. In the same circumstances, it is estimated that if the project 49.05 would use 27.2% renewable fraction, the COE will be approximately 55M$ which is much higher than the COE of the current project. Furthermore, according to the outputs of the HOMER platform, the capacity of the shortage as long as the unmet load is zero for the integration of these energy resources. However, there is still required more analysis through DIgSILENT Power Factory in order to investigate the reliability of the system as the HOMER Pro cannot consider so many parameters such as different failures in transmission lines and transformers. Therefore, the reliability of the system is investigated by considering different possible failures in the Donald network in the next subsection. As will be shown in later sections of this report, the international technical standards and requirements (introduced by IEEE and IEC) imposed several strict constraints on the interconnection of microgrids to the utility main grid to ensure safety and power quality. These requirements lead to the settings outlined in this section.

Table 6: Comparison of the setting between the current project (40.06) and project 49.05 (for Donald)

Categories	This project	Project 49.05
Operation mode	Islanded	Islanded
Load (kW)	2,355	2,360
PV (kW)	3,595	1,190
DG (kW)	2,730	1,900
Battery (kW)	840	43
Converter (kW)	607	98.2
NPC (M$)	47.7	34.35
COE ($/kWh)	0.323	0.375
Renewable fraction (%)	27.2	17

5.3 Data analysis and Scenarios Design

As discussed earlier, due to a range of issues, we are not able to obtain a detailed appliance modelling of the loads in the areas of interest (Donald and Tarnagulla), and nor are we able to obtain detailed preference profiles of the customers associated with the NMIs of the smart meters from the dataset. Subsequently, to perform technical analysis on the impact a microgrid with a specific design and size, we have designed a number of scenarios and perform what-if analyses on these scenarios. In this section, we outline the method we use for data analysis and scenarios design.

5.3.1. Critical Infrastructure

Before designing the scenarios, it is important to identify critical infrastructure to determine the critical loads. To do this we refer to the field research, clustering techniques and hourly energy consumption pattern reported by clean energy council [11]

It is observed that there is a hospital and a retirement/aged-care accommodation building located in Donald 3480 area as can be seen from **Figure 15**. We consider such customers as being part of **Category 0** (**Community critical load**). An example was given (see **Figure 16**) has a typical energy consumption curve of accommodation building, which involve a morning peak and a night peak. In the middle of the day accommodation services are free from its duty since most customers will have activity outside the services which reduce the energy load at that period. The number and type of critical infrastructure are manually defined by Google map search, and the final consumption data for scenarios are simulated by combining Clean Energy Council report [11] and data analysis.

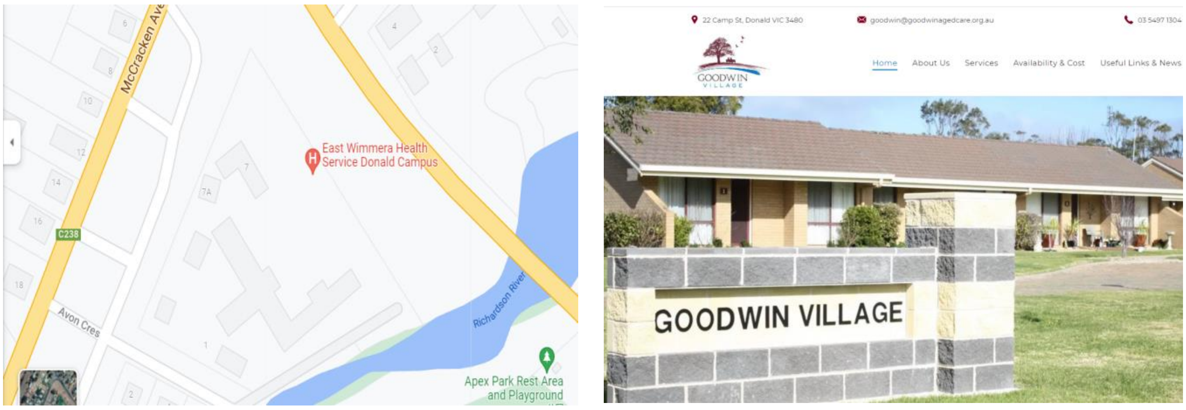


Figure 15: Google map location of Wimmera hospital and appearance of Goodwin aged accommodation building in Donald postcode 3480

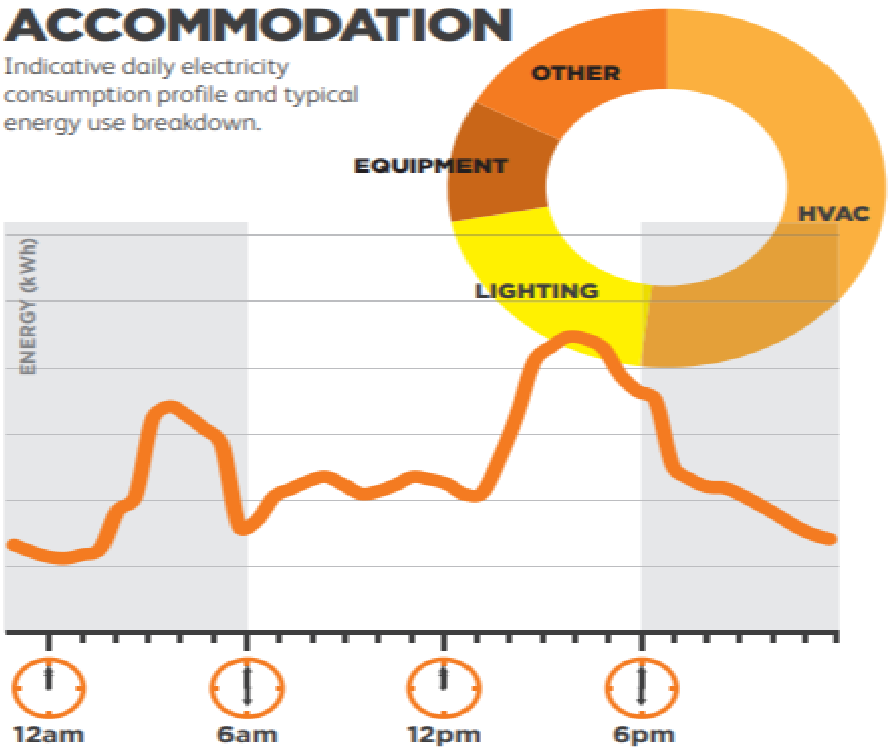


Figure 16: A typical energy consumption of accommodation building based on data analysis carried out by Clean Energy Council [11]

5.3.2. Scenarios

Based on limited operational cost, there are four scenarios have been selected for economic and reliability impacts analysis. Each of the region has two scenarios represents for the low boundary and up boundary for critical loads. The community critical loads are considered from two perspectives: (1) the infrastructure found from Google map and local business search and (2) the proportion of residual which is potentially critical/flexible for energy consumption.

5.3.2.1. Scenario Design for Donald Area

- ***Scenario A - S1: lowest energy consumption standard***

This scenario set the lowest proportion for nice to have and must keep category. It contains:

Cat. 0 – community critical loads - Mean load 123kw

Assumptions: 1 supermarket, 1 hospital, 1 retirement accommodation village, 2 mobile towers, 3 local shops, 1 small medical centre, 2 pharmacies, 2 petrol stations, 2 public services, 2 banks, 3 tele-communication devices (or stations), 2 emergence services, and 5% residential houses with all-time care services' needs.

Cat. 1 - 2. Medium-flexibility loads - Mean load 760kw

Assumptions: All domestic farms business, 95% residential houses, 40% commercial business, 30% agriculture, and 30% industry.

Cat. 2 - 2. High-flexibility loads - Mean load 284kw

Assumptions: Everything remaining.

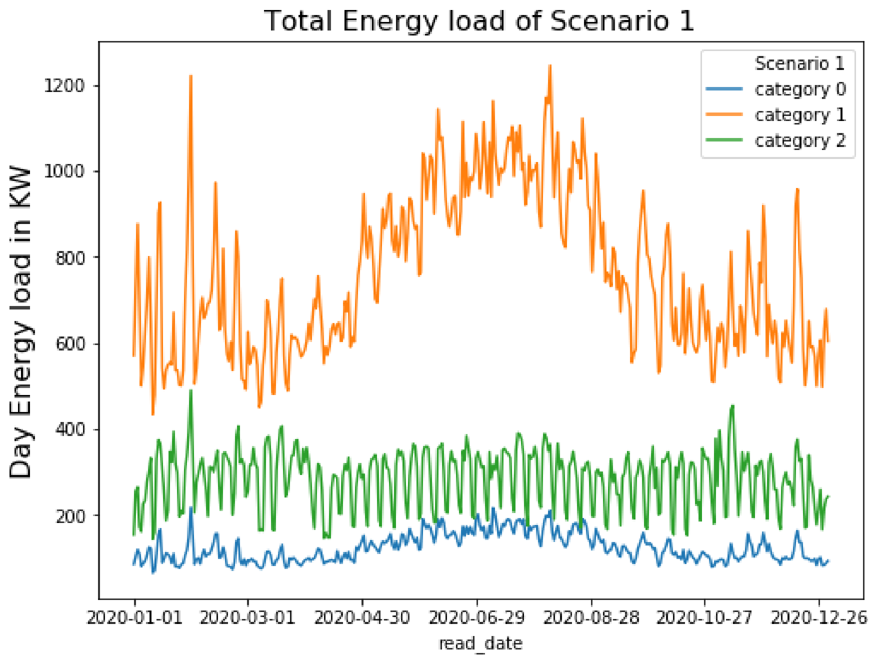


Figure 17: Total energy load for Donald: Scenario 1 separated by category

- ***Scenario B - S54: highest energy consumption standard***

This scenario sets the highest proportion for nice to have and must keep category. It contains:

Cat. 0 - community critical loads - Mean load 157kw

Assumptions: 1 supermarket, 1 hospital, 1 retirement accommodation village, 2 mobile towers, 5 local shops, 1 small medical centre, 3 pharmacies, 3 petrol stations, 3 public services, 3 banks, 6 tele-communication devices (or stations), 3 emergence services, and 10% residential houses with all-time care services' needs.

Cat. 1 - Medium-flexibility loads - Mean load 883kw

Assumptions: All domestic farms business, 90% residential houses, 70% commercial business, 60% agriculture, and 50% industry.

Cat. 2 - High-flexibility loads - Mean load 127kw

Assumptions: Everything remaining.

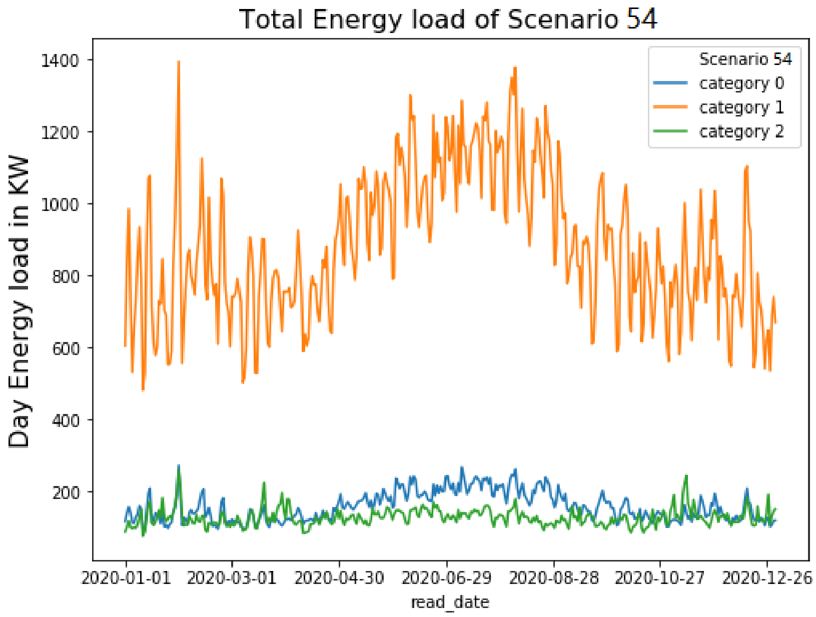


Figure 18: Total energy load for Donald: Scenario 54 separated by category

5.3.2.2. Scenario Design for Tarnagulla Area

- ***Scenario A - S1: lowest energy consumption standard***

This scenario set the lowest proportion for nice to have and must keep category. It contains:

Cat. 0 - community critical loads - Mean load 3.4kw

Assumptions: 1 mobile tower, 1 local shop, 1 emergence service, and 5% residential houses with all-time care services' needs.

Cat. 1 - Medium-flexibility loads - Mean load 77kw

Assumptions: All domestic farms business, 95% residential houses, 40% commercial business, 30% agriculture, and 30% industry.

Cat. 2 - High-flexibility loads - Mean load 15.8kw

Assumptions: Everything remaining.

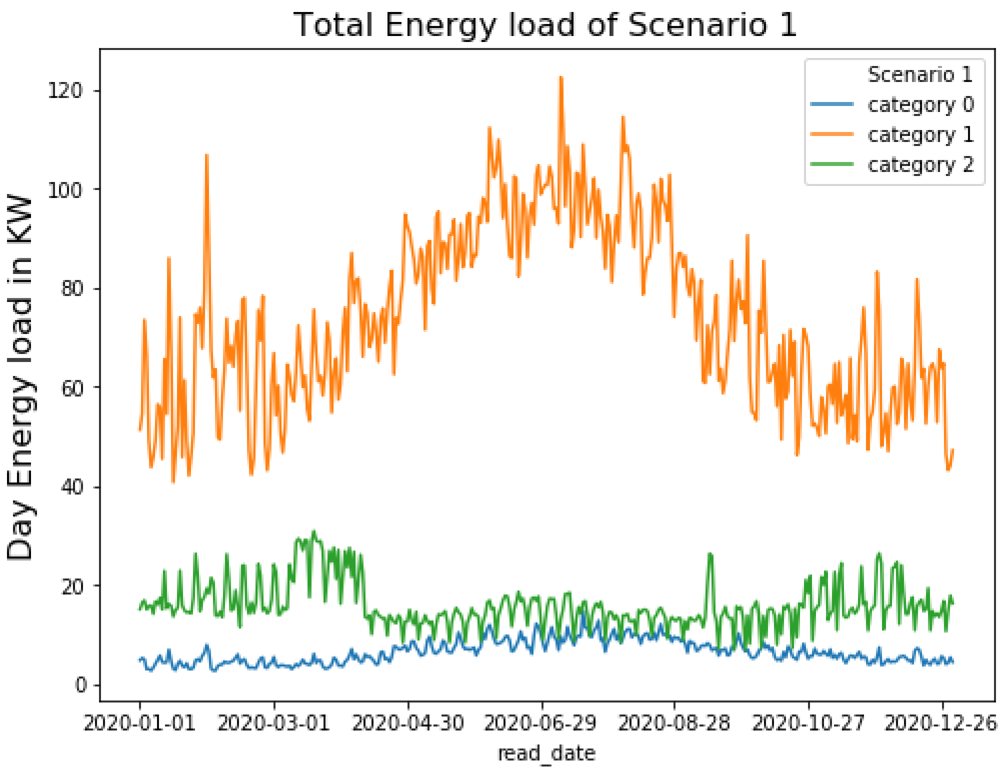


Figure 19: Total energy load for Tarnagulla: Scenario 1 separated by category

- ***Scenario B - S4: highest energy consumption standard***

This scenario sets the highest proportion for nice to have and must keep category. It contains:

Cat. 0 - community critical loads - Mean load 6.4kw

Assumptions: 1 mobile tower, 1 local shop, 1 emergence service, and 10% residential houses with all-time care services' needs.

Cat. 1 - Medium-flexibility loads - Mean load 83kw

Assumptions: All domestic farms business, 90% residential houses, 70% commercial business, 60% agriculture, and 50% industry.

Cat. 2 - High-flexibility loads - Mean load 6.6kw

Assumptions: Everything remaining.

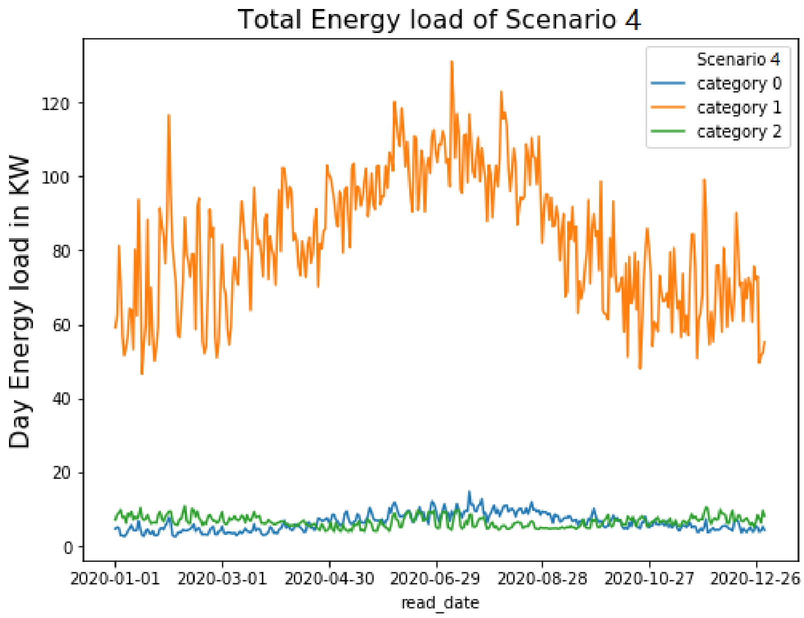


Figure 20: Total energy load for Tarnagulla: Scenario 4 separated by category

Table 7 summarizes the scenarios selected for detailed what-if analyses. Specifically, for both Donald and Tarnagulla areas, there are 2 main scenarios represent the 'lowest critical load estimation (**Scenario A**)' and 'highest critical load estimation (**Scenario B**)' which have been selected for further study.

Table 7: Summary of selected Scenarios

Name	Cat.0 (mean kW)	Cat.1 (mean kW)	Cat.2 (mean kW)
Donald-A	123	760	284
Donald-B	157	883	127
Tarnagulla-A	3.4	77	15.8
Tarnagulla-B	6.4	83	6.6

5.4. What-if Analyses and Results

5.4.1. Reliability Parameters

In order to investigate the reliability of the system under stakeholder impacts, two different analyses are conducted, which are the security analysis and generation adequacy evaluation. Regarding this, issue, **Table 8** to **Table 10** summarizes the different equipment's outages data. For this aim and to take into account the worst-case study, these reliability inputs are applied to all equipment in the power system for Donald and Tarnagulla networks. **Table 8** illustrates the failure rates of each equipment especially in terms of failure frequency and repair duration. For instance, the frequency of the failures for transformers is 0.002 per year and it takes almost 10 hours for repairing the failed transformer and this definition can be conducted for each equipment in **Table 8**. As can be seen from **Table 8**, these failure rates just consider some equipment without considering the different uncertainties of energy resources including PV panels, batteries, and DGs as all these energy resources are variables due to many reasons consisting of weather conditions, limitation in fuel for DGs, and constraints in batteries in terms of charging rates. Therefore, it is essential to take into account all these uncertainties for which **Table 9** gives detailed information for these suppliers. For example, **Table 9** indicates that the PV panels are available for 10 hours and are unavailable for 14 hours which is based on the availability of the sun during the daytime as long as its unavailability over the nights. It is assumed that the sun is available from 8 AM till 6 PM (10 hours) and is unavailable from 6 PM to 8 AM (14 hours). In addition, it is possible some usual outages in PV panels due to their failures in their equipment which these outrages are assumed 3 times a year and totally 270 hours per year. It is also assumed that the repair time for each outage is 90 hours by considering all issues such as replacing the PV panels. The similar information for the availability and outages for the batteries and DGs are also provided in **Table 9** and the similar interpretation is conducted as PV panels. In addition, in order to consider the behaviour of the load, the real load characteristics are used in hourly-based for the entire year 2020 as this method has higher accuracy. It is important to note that the reliability assessment based on security analysis cannot consider the behaviour of the generation (i.e. different uncertainties of PVs, batteries, and DGs); therefore, it is essential to analyse the system through the generation adequacy evaluation for which **Table 9** is mainly used as a stochastic model for this purpose. In all analyses, the outage expectancy is calculated by using the following expression:

$$\textit{Outage expectancy} = \textit{Failure frequency} \times \textit{Repair duration}$$

Table 8: Failure rates of equipment

Equipment	Failure data	
Overhead lines	*Failure frequency*	0.177 (1/a*km)
	Repair duration	10 (h)
	Transient fault frequency	12.05053 (1/a*km)
Busbars (22 kV)	*Failure frequency*	0.0104 (1/a)
	Additional failure frequency per connection	0.01 (1/a)
	Repair duration	20 (h)
Busbars (0.433 kV)	*Failure frequency*	1.99094 (1/a)
	Additional failure frequency per connection	0.01 (1/a)
	Repair duration	2 (h)
Transformers	*Failure frequency*	0.002 (1/a)
	Repair duration	10 (h)
CB at 22 kV feeder	*Time to actuate switch*	30 min
	CB fails to open	5 %
CB at secondary side of transformer	*Time to acuate switch*	1 min

Table 9: Stochastic model for distributed generation units used in DIgSILENT [12]

Energy Resource	State	Availability (%)	Probability (%)	Duration (h)	Failure Frequency (1/a)	Total Duration (h/a)
PV Panels	*1. Availability*	100	96.91781	10	849	8490
	2. Outages	0	3.082192	90	3	270

Batteries	*1. Availability*	100	95.79909	10	839.2	8392
	2. Outages	0	4.200913	80	4.6	368
DGs	*1. Availability*	100	93.63014	10	820.2	8202
	2. Outages	0	6.369863	60	9.3	558

Table 10: Common mode failure data for distributed generation units used in DIgSILENT [12]

Energy Resource	Failure Frequency (1/a)	Force Outage Rate (1/a)	Outage Expectancy	Repair Duration (h)
PV Panels	3	0.03	270	90
Batteries	4.6	0.04	360	80
DGs	9.3	0.06	558	60

5.4.2. Donald Network: Reliability Analysis' Results

5.4.2.1. Donald Network: Total customers (Residential + Non-residential)

In this subsection, the results of the reliability assessment for Donald area are presented under the different scenarios for total customers including residential and non-residential customers. For this aim, the reliability assessment in terms of security for each load point is provided in order to find the vulnerability of different loads under the pre-defined outages. **Table 11** shows the results for the LPENS for all scenarios. As can be seen from this table, the number of loads which are not served is the highest for installed load at busbar 15 as this busbar contains a huge of load. However, this vulnerability can be easily managed by distributing the loads. Overall, the mean value of the LPENS is almost 2 MWh per year for all customers if it is assumed all equipment participate in this assessment. Based on the results in **Table 11**, the following points can be concluded:

- **Scenarios A and B with categories 0 and 1:** If both residential and non-residential customers are considered, values of LPENS (load point energy not supplied) under categories 0 and 1 will be better for scenario A for all customers in all busbars. It means that the reliability of Donald with this scenario and this category is better for customers. For example, if we would consider the customers connected to busbar 1 in Donald network (i.e. Load(LV1) in **Table 11**), then, the amount of energy that they cannot get access in one year is 235.545h kWh with scenario A under category 0 and 1. For these customers at the same busbar with scenario B under categories 0 and 1, the energy not supplied is 257.224 kWh per year.
- **Scenarios A and B with category 0 only:** If both residential and non-residential customers are considered, values of LPENS (load point energy not supplied) under category 0 will be better for scenario A for all customers in all busbars. It means that the reliability of Donald with this scenario and this category is better for customers. For instance, the amount of energy not supplied for the customers connected in busbar 1 is 36.568 kWh per year with scenario A under category 0; however, this reliability index for scenario B under category 0 is 43.839 kWh per year.

This table gives good information about different load points and can help the company in locating critical loads in less vulnerable busbars. A similar interpretation is applicable for all busbars based on **Table 11**.

Table 11: The LPENS at different load points with all scenarios (Donald: Total customers)

Load points & Indices	Sc. A (Cat. 0 and 1)	Sc. A (Cat. 0)	Sc. B (Cat. 0 and 1)	Sc. B (Cat. 0)
Load(LV1)	0.235545	0.036568	0.257224	0.043839
Load(LV10)	2.013527	0.3126	2.198854	0.374752
Load(LV11)	2.473623	0.38403	2.701297	0.460383
Load(LV12)	0.200991	0.031204	0.21949	0.037408
Load(LV13)	0.884971	0.137392	0.966424	0.164708
Load(LV14)	2.589357	0.401998	2.827683	0.481923
Load(LV15)	7.120701	1.105489	7.776096	1.325284
Load(LV16)	0.936284	0.145358	1.02246	0.174258
Load(LV17)	1.998813	0.310316	2.182785	0.372013
Load(LV18)	0.361005	0.056046	0.394233	0.067189
Load(LV19)	0.401051	0.062263	0.437964	0.074642
Load(LV2)	0.584771	0.090786	0.638594	0.108836
Load(LV20)	1.197044	0.185841	1.30722	0.22279
Load(LV21)	0.579388	0.08995	0.632715	0.107834
Load(LV22)	0.176118	0.027342	0.192328	0.032779
Load(LV3)	1.756852	0.272751	1.918553	0.32698
Load(LV4)	0.982201	0.152487	1.072603	0.182804
Load(LV5)	0.177571	0.027568	0.193914	0.033049
Load(LV6)	2.487335	0.386159	2.716271	0.462935
Load(LV7)	2.170693	0.337	2.370485	0.404003
Load(LV8)	2.043091	0.31719	2.231139	0.380254
Load(LV9)	2.171112	0.337065	2.370942	0.404081

Table 12 also summarises all indices of any load point interruptions for all scenarios. For example, the results show that the interruption frequency of the load LV1 is almost 2.2 per year which causes 7 hours outages in a year. In addition, as can be seen from the results, the total customer interruption frequency and time are equal to load point interruption frequency and time, and this is due to aggregating the data in each busbar. According to **Table 12**, the rate of outages in each busbar is provided for which some examples are explained as follows for more clarifications:

- **The customers which connected to busbar 1:** With all scenarios and categories, the outage rate for those customers connected to busbar 1 is 2.187164 per year and the time duration of these outages in busbar 1 is 7.098633.
- **Maximum outage rate and duration:** The maximum outage rate belongs to the customers connected to busbar 11 for which the outage rate is 3.387987 per year with the duration of 23.48258 hours per year.
- **Minimum outage rate and duration:** The minimum outage rate belongs to the customers connected to busbar 1 as explained above.

In conclusion, the outage rates and the duration of outages depend on the system's equipment including the outages of transformers, transmission lines, busbars, and generation units.

Table 12: The load point interruption indices for all scenarios (Donald: Total customers)

Load points & Indices	LPIF (1/a)	LPIT (h/a)	ACIF (1/a)	ACIT (h/a)	TCIF (C/a)	TCIT (Ch/a)
Load(LV1)	2.187164	7.098633	2.187164	7.098633	2.187164	7.098633
Load(LV10)	3.09394	20.2273	3.09394	20.2273	3.09394	20.2273
Load(LV11)	3.387987	23.48258	3.387987	23.48258	3.387987	23.48258
Load(LV12)	2.720232	15.26436	2.720232	15.26436	2.720232	15.26436
Load(LV13)	2.843208	16.80239	2.843208	16.80239	2.843208	16.80239
Load(LV14)	2.754408	15.60715	2.754408	15.60715	2.754408	15.60715
Load(LV15)	2.84291	16.89955	2.84291	16.89955	2.84291	16.89955
Load(LV16)	2.89001	17.77664	2.89001	17.77664	2.89001	17.77664
Load(LV17)	2.979119	18.97511	2.979119	18.97511	2.979119	18.97511
Load(LV18)	2.635393	13.70838	2.635393	13.70838	2.635393	13.70838
Load(LV19)	2.756645	15.22902	2.756645	15.22902	2.756645	15.22902
Load(LV2)	2.334693	8.882155	2.334693	8.882155	2.334693	8.882155
Load(LV20)	2.319494	8.425124	2.319494	8.425124	2.319494	8.425124
Load(LV21)	2.535984	11.00048	2.535984	11.00048	2.535984	11.00048
Load(LV22)	2.742422	13.37537	2.742422	13.37537	2.742422	13.37537
Load(LV3)	2.257501	7.703524	2.257501	7.703524	2.257501	7.703524
Load(LV4)	2.378786	9.324222	2.378786	9.324222	2.378786	9.324222
Load(LV5)	2.613189	13.48569	2.613189	13.48569	2.613189	13.48569
Load(LV6)	2.723052	14.99222	2.723052	14.99222	2.723052	14.99222
Load(LV7)	2.943887	18.31716	2.943887	18.31716	2.943887	18.31716
Load(LV8)	3.021014	19.39546	3.021014	19.39546	3.021014	19.39546
Load(LV9)	2.944239	18.32069	2.944239	18.32069	2.944239	18.32069

In order to be more detailed about the system interruptions, the results for each scenario are presented for different months as the real characteristics of the loads are utilized in simulations. For this aim, the possible highest consumption time is selected for all months (date 15^{th} of each month) which is almost 8 PM. **Figure 21** to **Figure 28** indicate the simulation results for the Donald network (total customers of each scenario) under different scenarios and categories by focusing on the energy not supplied and average energy not supplied indices.

1. Scenario A with categories 0 and 1

Figure 21 shows the reliability analysis results for the index ENA and AENS in more detail per month by considering total customers in scenario A with categories 0 and 1. It is important to note that the indexes ENS and AENS are different from LPENS. In fact, LPENS gives the results for each busbar, but ENS and AENS give the energy not supplied and its average for the total system. As we know, the consumption of the customers is different in each month, therefore, it is expected different energy not supplied for customers in each month. The results are summarized as follows:

The customers can expect the maximum energy not supplied in January for which it is 41.4647 MWh per year and the minimum energy not supplied belongs to March which is 26.5436 MWh per year.

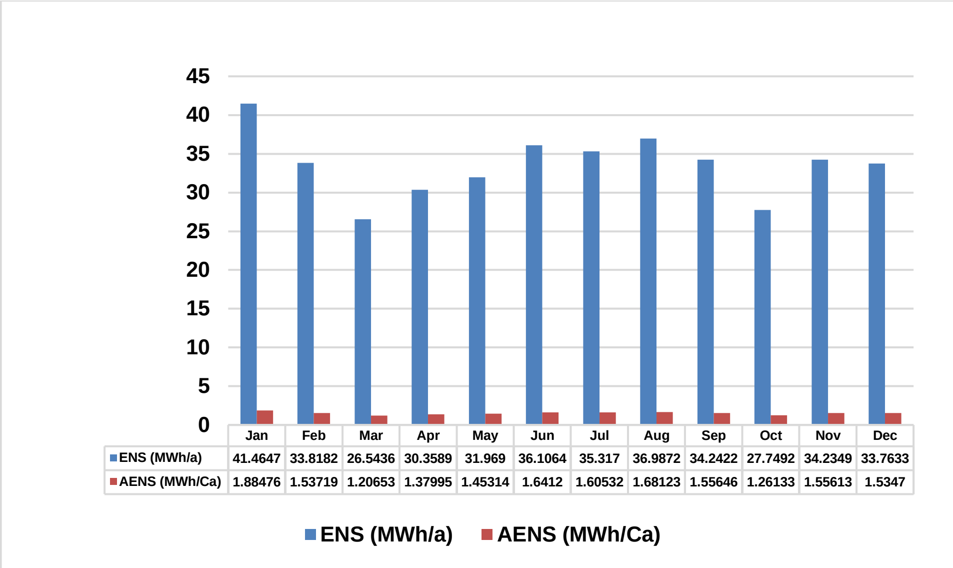


Figure 21: The ENS and AENS under scenario A with categories 0 and 1 (Donald: Total customers)

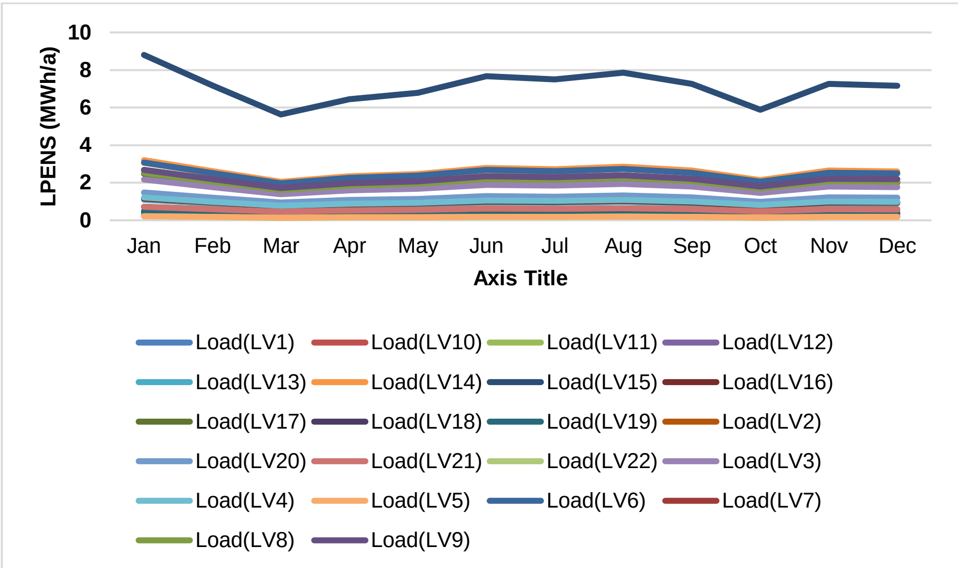
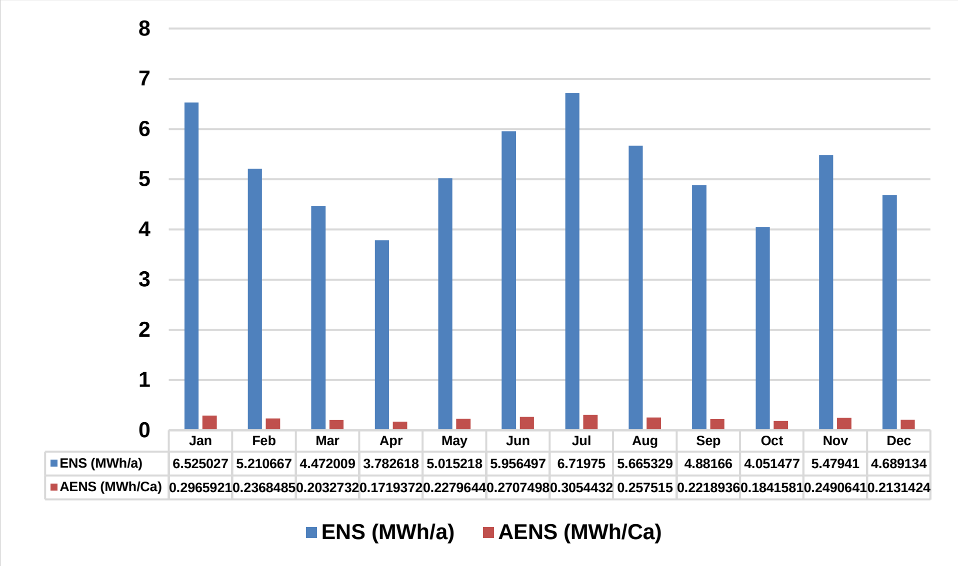


Figure 22: The LPENS under scenario A with categories 0 and 1 (Donald: Total customers)

2. Scenario A with category 0

As **Figure 24** shows, with scenario A under category 0, the maximum energy not supplied is 6.71975 MWh per year which can occur in July while the minimum ENS is 3.782618, which can happen in April.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ENS (MWh/a)	6.525027	5.210667	4.472009	3.782618	5.015218	5.956497	6.71975	5.665329	4.88166	4.051477	5.47941	4.689134
AENS (MWh/Ca)	0.2965921	0.2368485	0.2032732	0.1719372	0.2279644	0.2707498	0.3054432	0.257515	0.2218936	0.1841581	0.2490641	0.2131424

Figure 23: The ENS and AENS under scenario A with category 0 (Donald: Total customers)

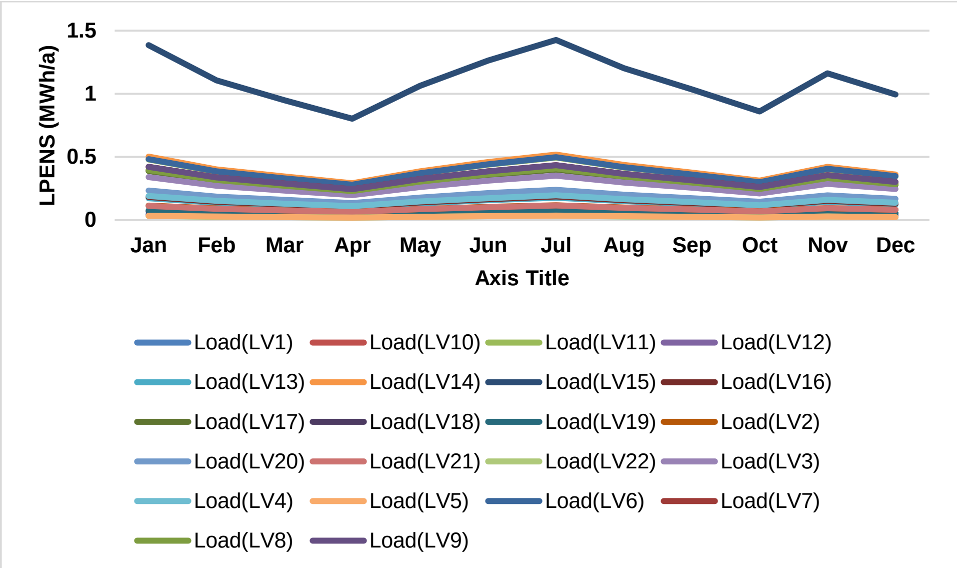
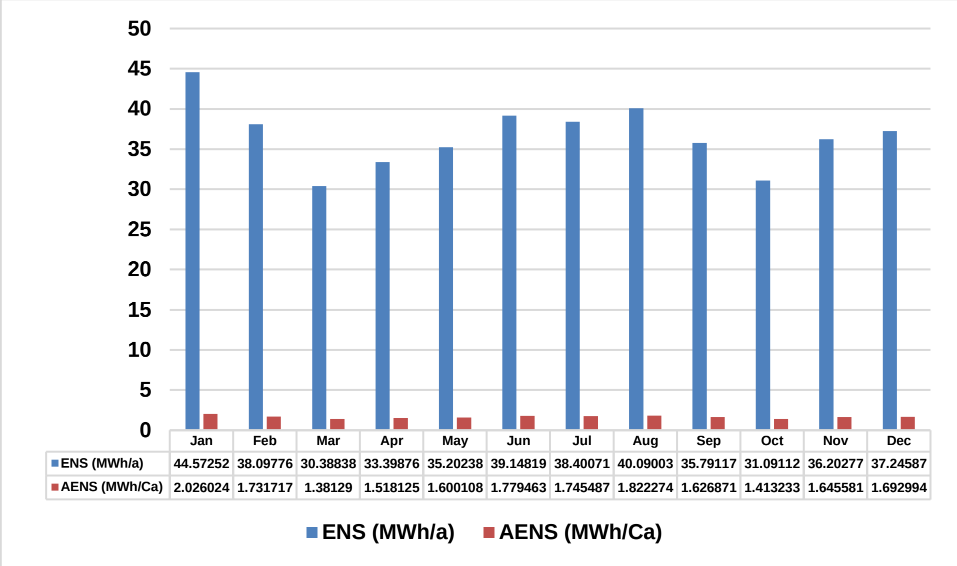


Figure 24: The LPENS under scenario A with category 0 (Donald: Total customers)

3. Scenario B with categories 0 and 1

Scenario B under categories 0 and 1 is almost as scenario A with categories 0 and 1, but the indexes ENS and AENS are slightly a bit high.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ENS (MWh/a)	44.57252	38.09776	30.38838	33.39876	35.20238	39.14819	38.40071	40.09003	35.79117	31.09112	36.20277	37.24587
AENS (MWh/Ca)	2.026024	1.731717	1.38129	1.518125	1.600108	1.779463	1.745487	1.822274	1.626871	1.413233	1.645581	1.692994

Figure 25: The ENS and AENS under scenario B with categories 0 and 1 (Donald: Total customers)

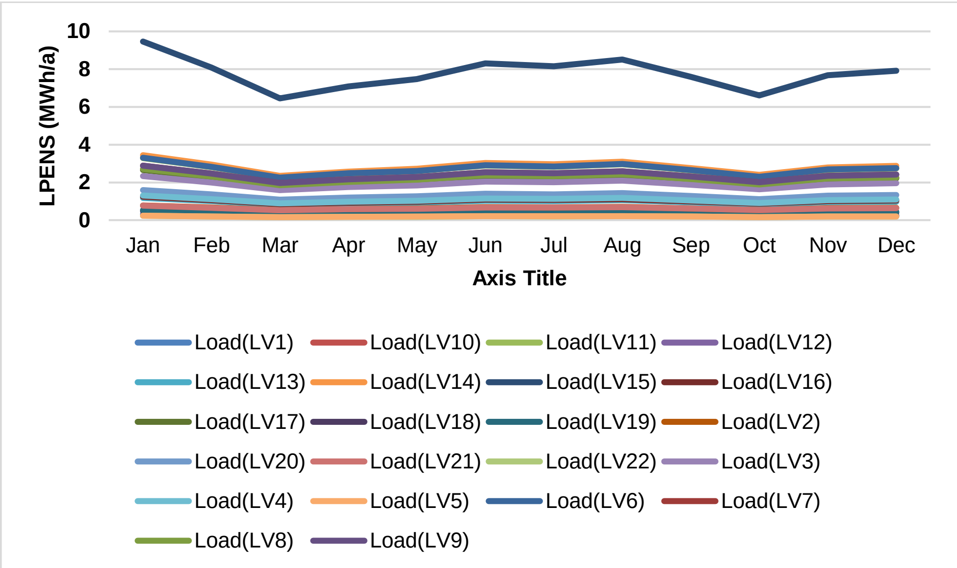
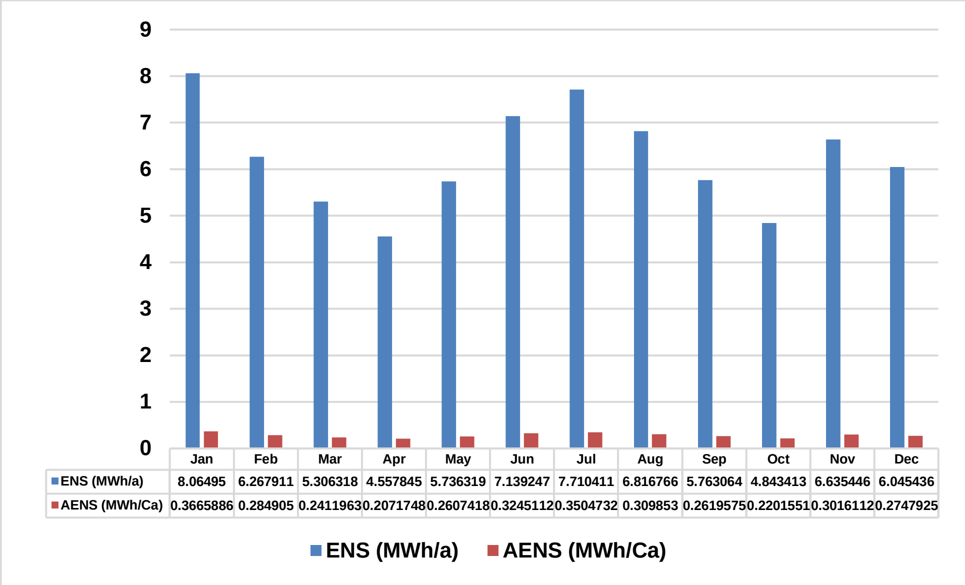


Figure 26: The LPENS under scenario B with categories 0 and 1 (Donald: Total customers)

4. Scenario B with category 0

The scenario B with category 0 is similar to scenario A with category 0, but the values for ENS and AENS is slightly higher than scenario A.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ENS (MWh/a)	8.06495	6.267911	5.306318	4.557845	5.736319	7.139247	7.710411	6.816766	5.763064	4.843413	6.635446	6.045436
AENS (MWh/Ca)	0.3665886	0.284905	0.2411963	0.2071748	0.2607418	0.3245112	0.3504732	0.309853	0.2619575	0.2201551	0.3016112	0.2747925

Figure 27: The ENS and AENS under scenario B with category 0 (Donald: Total customers)

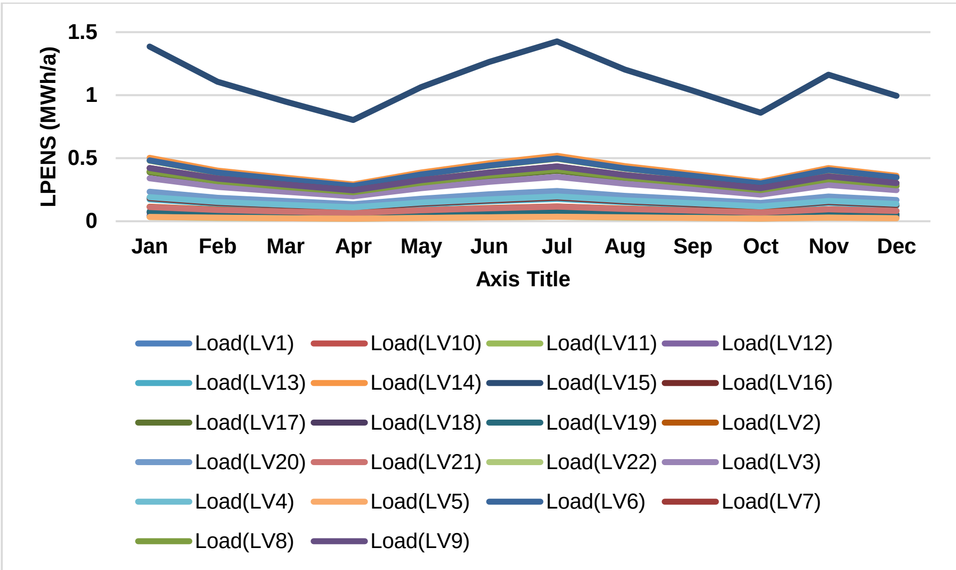


Figure 28: The LPENS under scenario B with category 0 (Donald: Total customers)

For investigation of the reliability for the entire system, the reliability indices for the average system, which considers all load points. **Figure 22** displays the system average indices for all scenarios in terms of outage frequency and time duration of the system outages. As can be seen from this table, the system average reliability indices are equal because the reliability of the loads depends on busbars/transmission/CBs outage information. In addition, the ENS and AENS have different values as these indices depend on the load values. According to the results, the reliability of the loads for scenario A is better than scenario B under both categories. It is worth to note that the system average indices cannot give an accurate result for evaluating the reliability of the system as the more vulnerable load points might not be recognized and the results for the load points can be chosen a better way for evaluation (i.e. **Table 11** and **Table 12**).

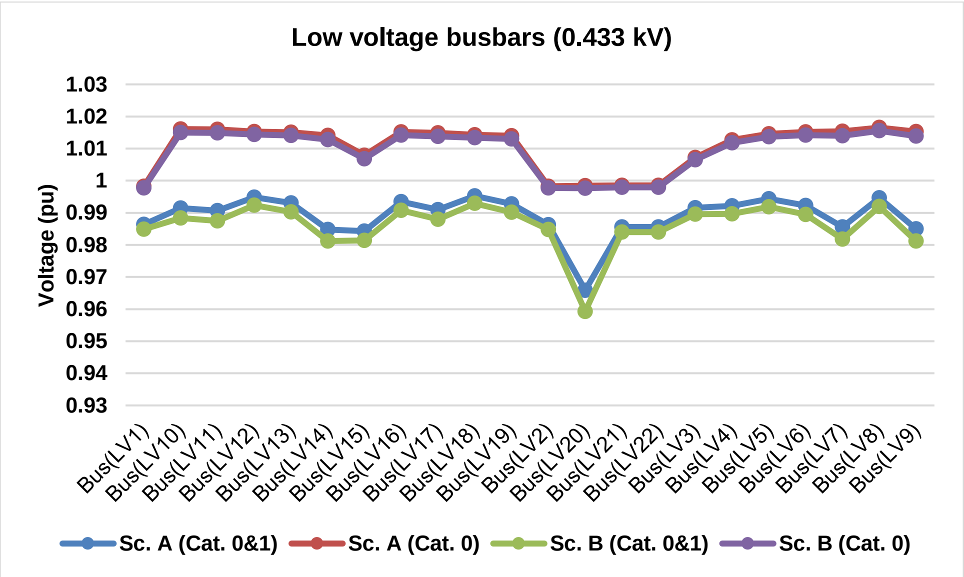
Table 13: The reliability indices with different scenarios (Donald: Total customers)

Scenarios & Indices	SAIFI (1/Ca)	CAIFI (1/Ca)	SAIDI (h/Ca)	CAIDI (h)	ENS (MWh/a)	AENS (MWh/Ca)	ASIFI (1/a)	ASIDI (h/a)
Sc. A (Cat. 0 and 1)	2.722967	2.722967	14.7406	5.413433	33.54204	1.524638	2.737804	15.03845
Sc. A (Cat. 0)	2.722967	2.722967	14.7406	5.413433	5.207403	0.2367	2.737804	15.03845
Sc. B (Cat. 0 and 1)	2.722967	2.722967	14.7406	5.413433	36.62927	1.664967	2.737804	15.03845
Sc. B (Cat. 0)	2.722967	2.722967	14.7406	5.413433	6.242744	0.283761	2.737804	15.03845

Apart from the reliability indices, the entire designed system must satisfy the balance between generation and consumption. From this view, **Table 14** provides the load flow analysis for the total customers of each scenario. In addition, the voltage of all busbars is shown in **Table 20** for which the voltage profiles meet the standard limitations.

Table 14: The load flow analysis under different scenarios (Donald: Total customers)

	Generation		Consumption		Loss	
Scenarios & Indices	P (kW)	Q (kVAr)	P (kW)	Q (kVAr)	P (kW)	Q (kVAr)
Sc. A (Cat. 0 and 1)	2254.798	1405.027	2245.132	1304.833	9.665198	100.1966
Sc. A (Cat. 0)	193.0481	311.8097	181.2185	48.67535	11.8333	193.0481
Sc. B (Cat. 0 and 1)	2484.768	1561.585	2476.709	1439.421	8.058396	122.1694
Sc. B (Cat. 0)	447.8792	246.0854	401.9986	233.6348	45.89269	12.45491



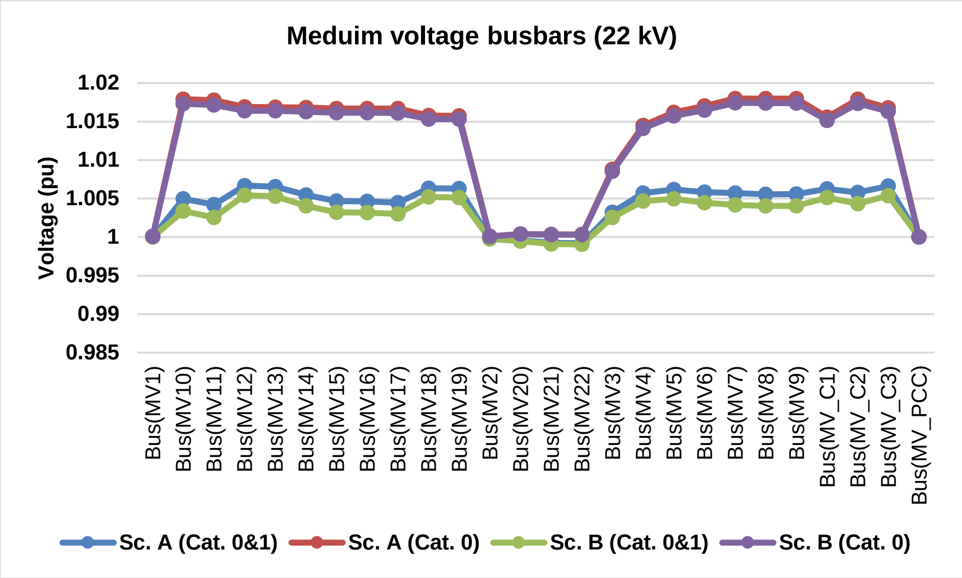


Figure 29: The voltages of different busbars for all scenarios (Donald: Total customers)

5.4.2.2. Donald Network: Residential customers

In this section, a similar analysis as Section 5.2.1.1.1 is conducted by considering the residential customers for Donald area for which **Table 15** and **Table 16** along with **Figure 30** to **Figure 36** summarizes the results.

Table 15: The LPENS at different load points with all scenarios (Donald: Residential customers)

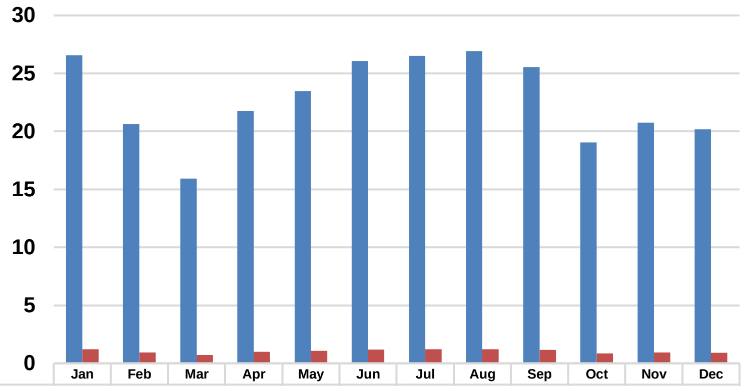
Load points & Indices	Sc. A (Cat. 0 and 1)	Sc. A (Cat. 0)	Sc. B (Cat. 0 and 1)	Sc. B (Cat. 0)
Load(LV1)	0.16008	0.010391	0.16008	0.01739632
Load(LV10)	1.368428	0.088831	1.368428	0.1487106
Load(LV11)	1.681117	0.109129	1.681117	0.1090486
Load(LV12)	0.136597	0.008867	0.136597	0.01484433
Load(LV13)	0.601441	0.039042	0.601441	0.06536017
Load(LV14)	1.759772	0.114234	1.759772	0.1912389
Load(LV15)	4.839352	0.314143	4.839352	0.313913
Load(LV16)	0.636315	0.041306	0.636315	0.06914993
Load(LV17)	1.358428	0.088181	1.358428	0.08811677
Load(LV18)	0.245346	0.015926	0.245346	0.02666233
Load(LV19)	0.272561	0.017693	0.272561	0.02961992
Load(LV2)	0.397421	0.025798	0.397421	0.04318873
Load(LV20)	0.813532	0.05281	0.813532	0.08840855
Load(LV21)	0.393762	0.025561	0.393762	0.04279112
Load(LV22)	0.119693	0.00777	0.119693	0.01300732
Load(LV3)	1.193987	0.077507	1.193987	0.1297536

Load(LV4)	0.667521	0.043332	0.667521	0.04329989
Load(LV5)	0.12068	0.007834	0.12068	0.0131146
Load(LV6)	1.690436	0.109734	1.690436	0.183704
Load(LV7)	1.475241	0.095764	1.475241	0.1603182
Load(LV8)	1.38852	0.090135	1.38852	0.09006877
Load(LV9)	1.475525	0.095783	1.475525	0.1603491

Table 16: The load point interruption indices for all scenarios (Donald: Residential customers)

Load points & Indices	LPIF (1/a)	LPIT (h/a)	ACIF (1/a)	ACIT (h/a)	TCIF (C/a)	TCIT (Ch/a)
Load(LV1)	2.187164	7.098633	2.187164	7.098633	2.187164	7.098633
Load(LV10)	3.09394	20.2273	3.09394	20.2273	3.09394	20.2273
Load(LV11)	3.387987	23.48258	3.387987	23.48258	3.387987	23.48258
Load(LV12)	2.720232	15.26436	2.720232	15.26436	2.720232	15.26436
Load(LV13)	2.843208	16.80239	2.843208	16.80239	2.843208	16.80239
Load(LV14)	2.754408	15.60715	2.754408	15.60715	2.754408	15.60715
Load(LV15)	2.84291	16.89955	2.84291	16.89955	2.84291	16.89955
Load(LV16)	2.89001	17.77664	2.89001	17.77664	2.89001	17.77664
Load(LV17)	2.979119	18.97511	2.979119	18.97511	2.979119	18.97511
Load(LV18)	2.635393	13.70838	2.635393	13.70838	2.635393	13.70838
Load(LV19)	2.756645	15.22902	2.756645	15.22902	2.756645	15.22902
Load(LV2)	2.334693	8.882155	2.334693	8.882155	2.334693	8.882155
Load(LV20)	2.319494	8.425124	2.319494	8.425124	2.319494	8.425124
Load(LV21)	2.535984	11.00048	2.535984	11.00048	2.535984	11.00048
Load(LV22)	2.742422	13.37537	2.742422	13.37537	2.742422	13.37537
Load(LV3)	2.257501	7.703524	2.257501	7.703524	2.257501	7.703524
Load(LV4)	2.378786	9.324222	2.378786	9.324222	2.378786	9.324222
Load(LV5)	2.613189	13.48569	2.613189	13.48569	2.613189	13.48569
Load(LV6)	2.723052	14.99222	2.723052	14.99222	2.723052	14.99222
Load(LV7)	2.943887	18.31716	2.943887	18.31716	2.943887	18.31716
Load(LV8)	3.021014	19.39546	3.021014	19.39546	3.021014	19.39546
Load(LV9)	2.944239	18.32069	2.944239	18.32069	2.944239	18.32069

5. Scenario A with categories 0 and 1



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ENS (MWh/a)	26.5643	20.6431	15.9404	21.7815	23.4845	26.0673	26.5033	26.9352	25.543	19.0445	20.7431	20.1859
AENS (MWh/Ca)	1.20747	0.93832	0.72456	0.99007	1.06748	1.18488	1.20469	1.22433	1.16105	0.86566	0.94287	0.91754

Figure 30: The ENS and AENS under scenario A with categories 0 and 1 (Donald: Residential customers)

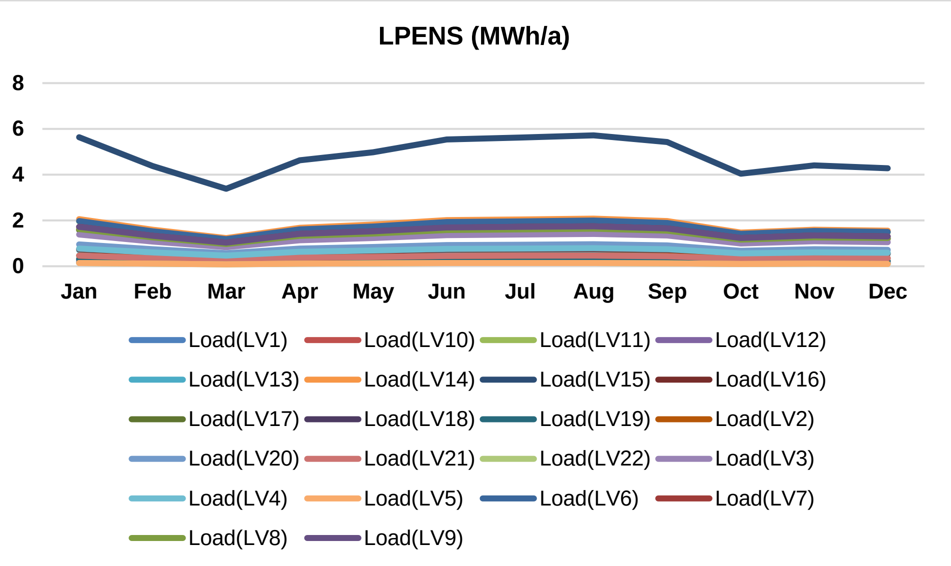
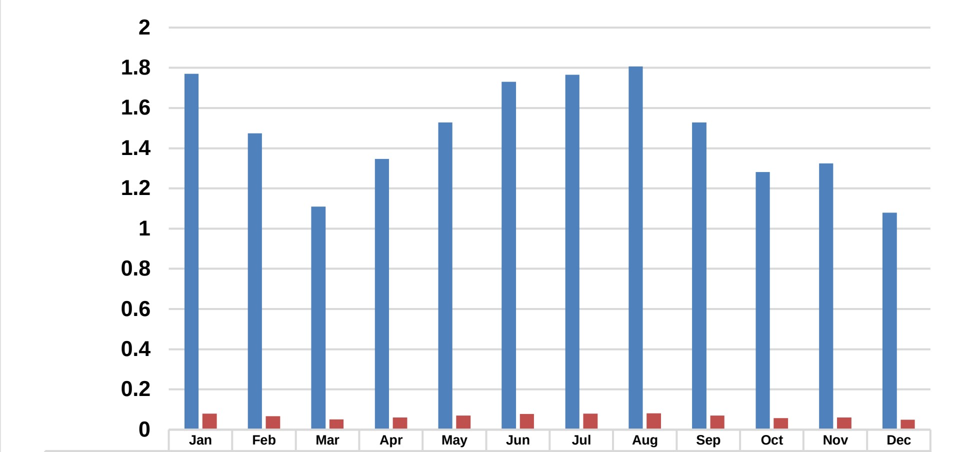


Figure 31: The LPENS under scenario A with categories 0 and 1 (Donald: Residential customers)

6. Scenario A with category 0



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ENS (MWh/a)	1.769799	1.474763	1.110087	1.347184	1.528435	1.729822	1.765041	1.805958	1.528744	1.28073	1.324793	1.079006
AENS (MWh/Ca)	0.0804454	0.0670347	0.0504585	0.0612357	0.0694743	0.0786283	0.0802291	0.082089	0.0694883	0.058215	0.0602179	0.0490458

ENS (MWh/a) AENS (MWh/Ca)

Figure 32: The ENS and AENS for Donald area under scenario A with category 0 (Residential customers)

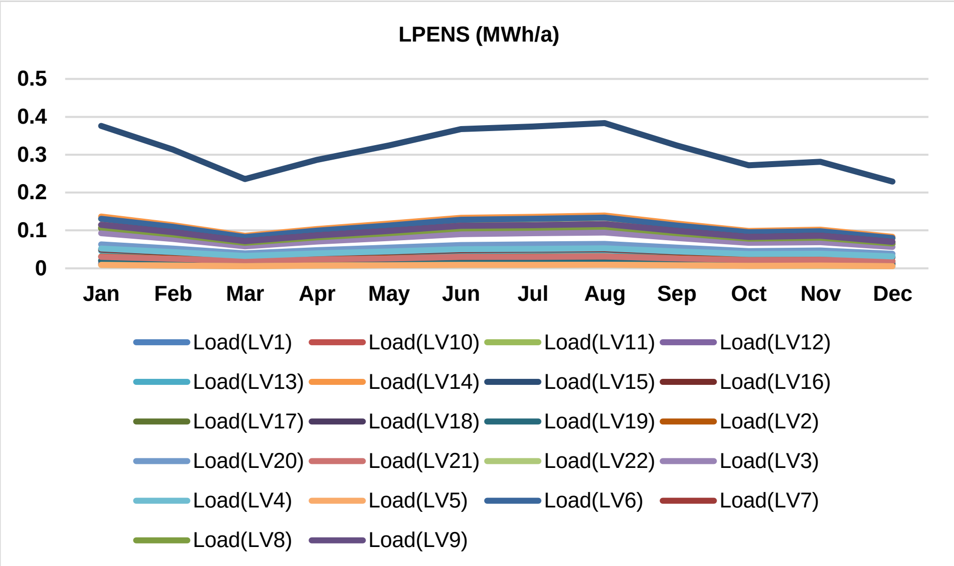


Figure 33: The LPENS under scenario A with category 0 (Donald: Residential customers)

Note: *residential results for scenario B with categories 0 and 1 are as same as scenario A as the data are the same for this customer (Based on provided data).*

7. Scenario B with category 0

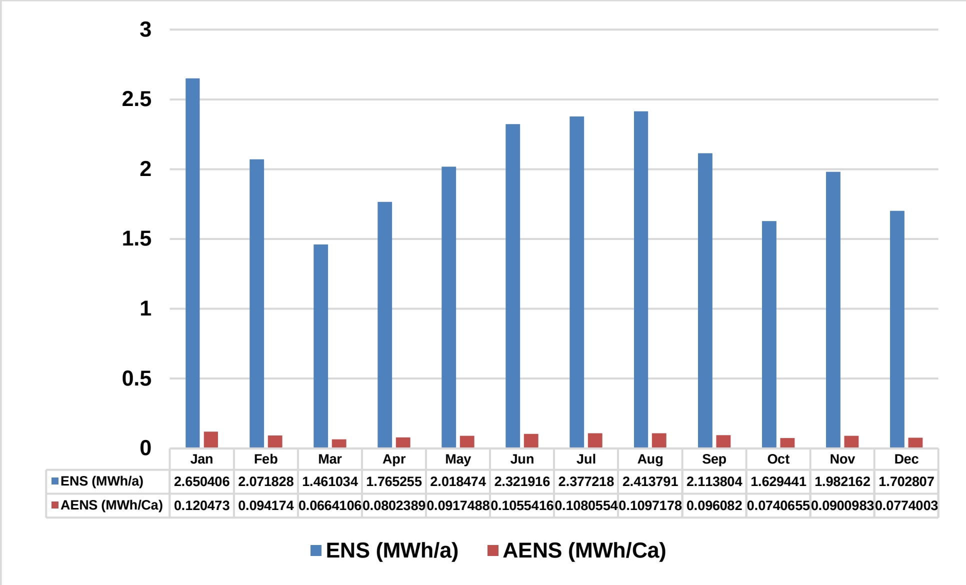


Figure 34: The ENS and AENS under scenario B with category 0 (Donald: Residential customers)

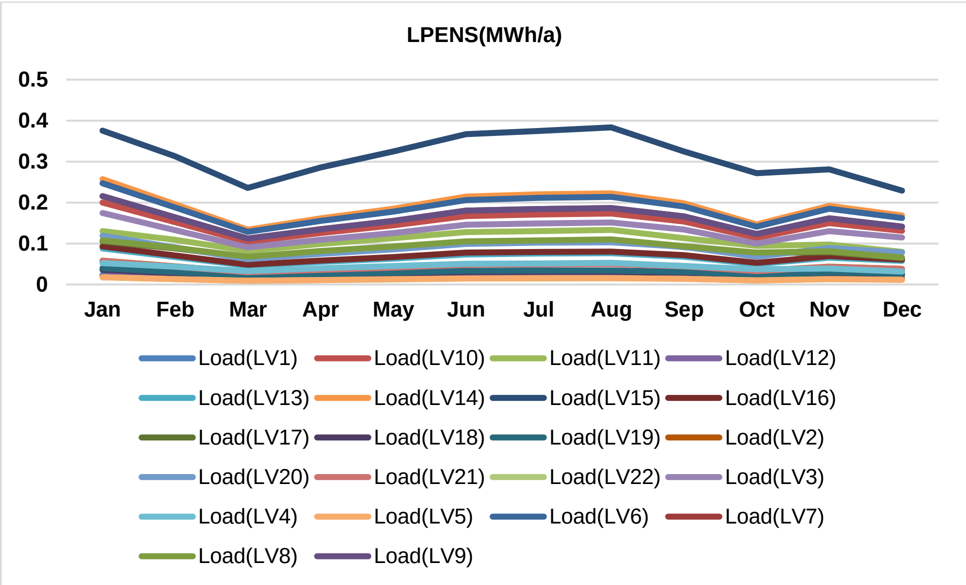


Figure 35: The LPENS under scenario B with category 0 (Donald: Residential customers)

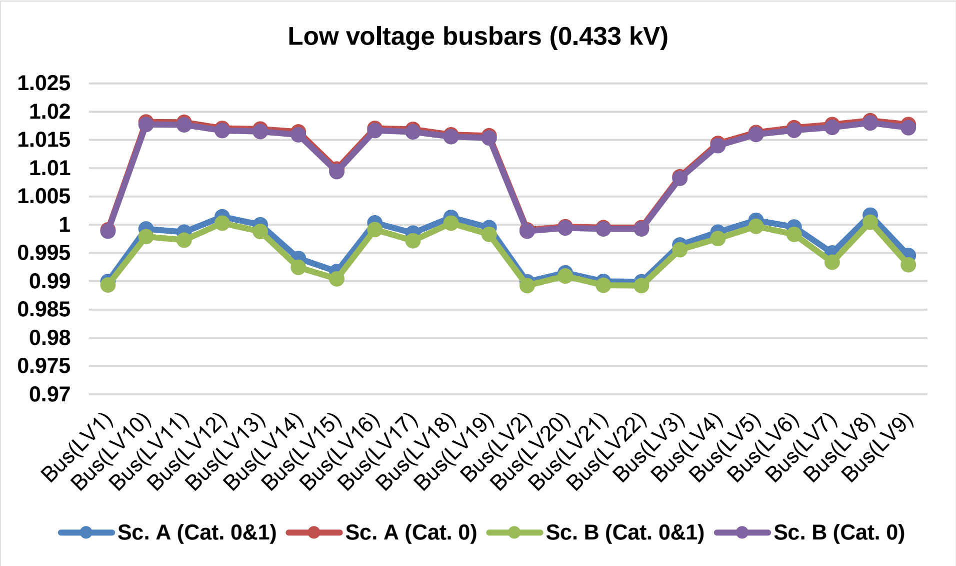
Table 17: The reliability indices with different scenarios (Donald: Residential customers)

Scenarios & Indices	SAIFI (1/Ca)	CAIFI (1/Ca)	SAIDI (h/Ca)	CAIDI (h)	ENS (MWh/a)	AENS (MWh/Ca)	ASIFI (1/a)	ASIDI (h/a)
Sc. A (Cat. 0 and 1)	2.722967	2.722967	14.7406	5.413433	22.79575	1.036171	2.737804	15.03845
Sc. A (Cat. 0)	2.722967	2.722967	14.7406	5.413433	1.47977	0.067262	2.737804	15.03845

Sc. B (Cat. 0 and 1)	2.722967	2.722967	14.7406	5.413433	22.79575	1.036171	2.737804	15.03845
Sc. B (Cat. 0)	2.722967	2.722967	14.7406	5.413433	2.043076	0.092867	2.71006	14.62395

Table 18: The load flow analysis under different scenarios (Donald: Residential customers)

	Generation		**Consumption**		**Loss**	
Scenarios & Indices	**P (kW)**	**Q (kVAr)**	**P (kW)**	**Q (kVAr)**	**P (kW)**	**Q (kVAr)**
Sc. A (Cat. 0 and 1)	1364.647	818.8572	1342.283	780.1123	22.36328	38.74495
Sc. A (Cat. 0)	128.2483	53.44405	71.74985	41.69979	56.51672	11.74817
Sc. B (Cat. 0 and 1)	1364.647	818.8572	1342.283	780.1123	22.36328	38.74495
Sc. B (Cat. 0)	172.6179	80.96829	117.4945	69.28747	55.14078	11.68459



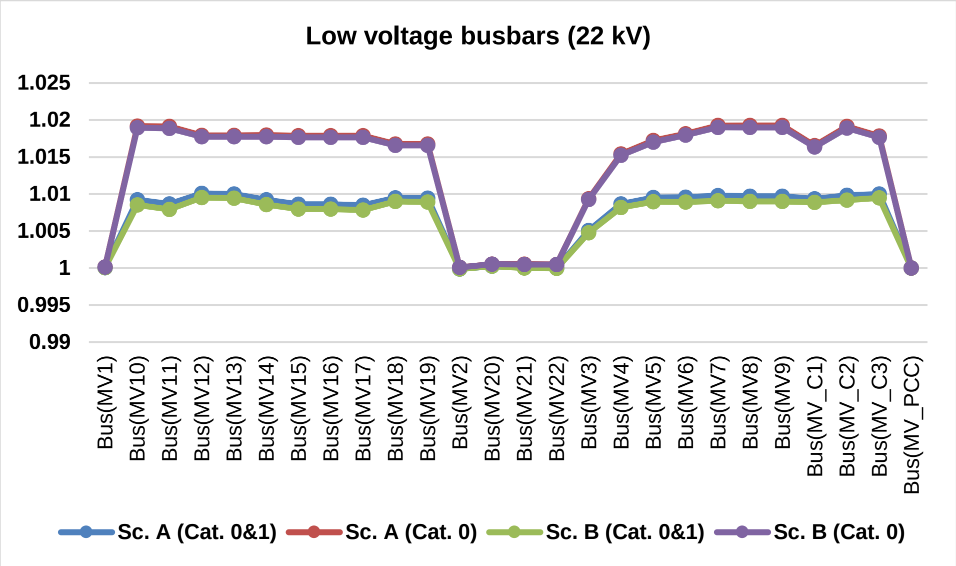


Figure 36: The voltages of different busbars for all scenarios (Donald: Residential customers)

5.4.2.3. Generation Adequacy Evaluation: Donald Network

As early stated, the reliability assessment in terms of security cannot guarantee the reliability of the entire system as it cannot consider the generation's uncertainties. Therefore, the generation adequacy evaluation is presented by considering the total customers of each scenario as long as residential customers of each scenario for which **Table 19** to **Table 22** show the results of this assessment. The integration of batteries into DGs reduces the probability of the loss of loads and consequently expected demand not supplied. By considering all factors including the cost of energy (COE) and generation adequacy indexes, the integration of the PV, batteries, and DG can be a better choice for Donald area. It is worth to note that the percentage of losses is assumed as 10%.

Table 19: Generation adequacy analysis under scenario A with categories 0 and 1 (Donald: Total customers)

Reliability Indices	Index	PV + DG + Battery	PV + Battery
Loss of Load Probability (%)	Average (LOLP)	0	0
	Lower Confidence Level	0	0
	Upper Confidence Level	0	0
Expected Demand Not Supplied (kW)	Average (EDNS)	0	0
	Lower Confidence Level	0	0
	Upper Confidence Level	0	0
Costs	Lower NPC ($)	47.4M	157M
	Lower COE ($/kWh)	0.323	1.07

Table 20: Generation adequacy analysis under scenario A with categories 0 and 1 (Donald: Residential customers)

Reliability Indices	Index	PV + DG + Battery	PV + Battery
Loss of Load Probability (%)	Average (LOLP)	0	0
	Lower Confidence Level	0	0
	Upper Confidence Level	0	0
Expected Demand Not Supplied (kW)	Average (EDNS)	0	0
	Lower Confidence Level	0	0
	Upper Confidence Level	0	0

Table 21: Generation adequacy analysis under scenario B with categories 0 and 1 (Donald: Total customers)

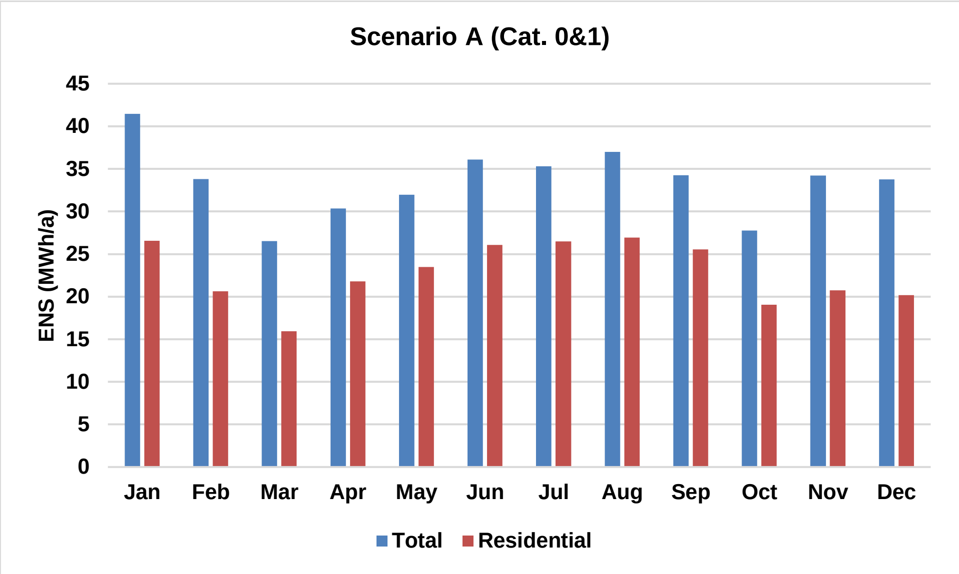
Reliability Indices	Index	PV + DG + Battery	PV + Battery
Loss of Load Probability (%)	Average (LOLP)	0	0
	Lower Confidence Level	0	0
	Upper Confidence Level	0	0
Expected Demand Not Supplied (kW)	Average (EDNS)	0	0
	Lower Confidence Level	0	0
	Upper Confidence Level	0	0
Costs	Lower NPC ($)	43.6M	142M
	Lower COE ($/kWh)	0.306	0.993

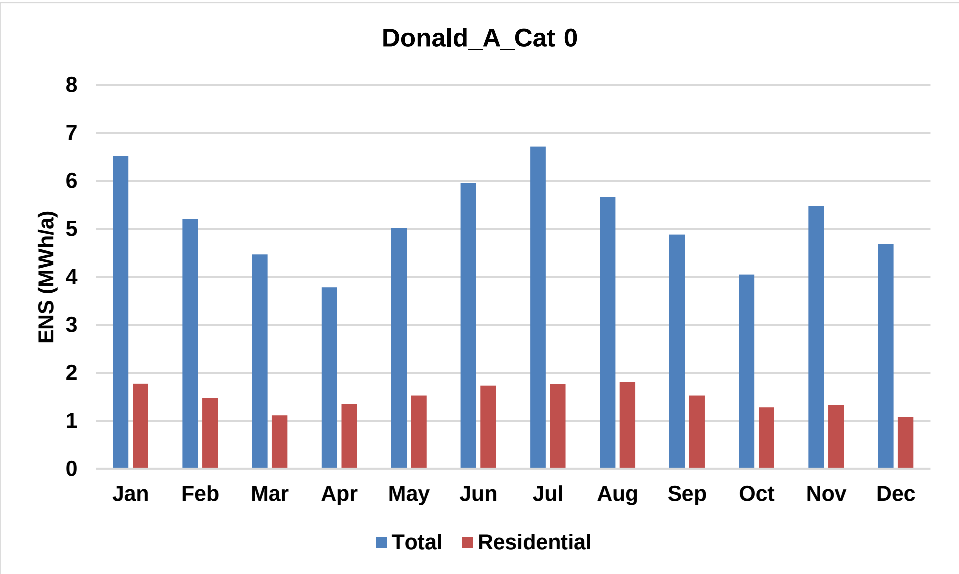
Table 22: Generation adequacy analysis under scenario B with categories 0 and 1 (Donald: Residential customers)

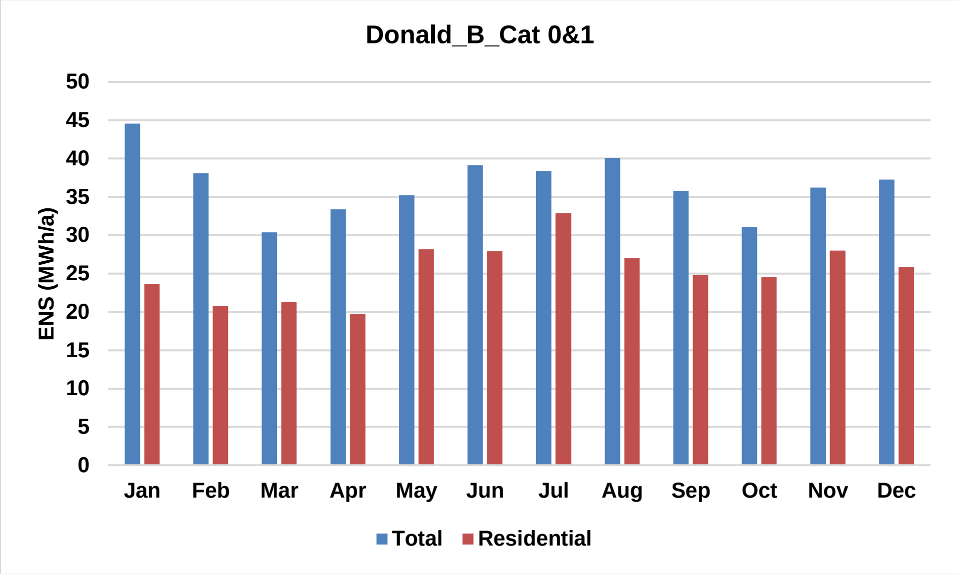
Reliability Indices	Index	PV + DG + Battery	PV + Battery
Loss of Load Probability (%)	Average (LOLP)	0	0
	Lower Confidence Level	0	0
	Upper Confidence Level	0	0
Expected Demand Not Supplied (kW)	Average (EDNS)	0	0
	Lower Confidence Level	0	0
	Upper Confidence Level	0	0

5.4.2.4. Comparison Results Between Total and Residential Customers: Donald Network

Figure 37 shows comparison results in terms of ENS for each scenario while the total and residential customers are considered. As can be seen from this comparison, the residential customers have the highest proportion of vulnerability for losing energy in the presence of the system's outages compared to all other customers under categories 0 and 1. Therefore, categories 0 and 1 can be a better system for non-residential customers. On the other hand, category 0 in both scenarios has the lowest probability of energy loss for residential customers. Therefore, category 0 can be a better microgrid for residential customers rather than non-residential customers.







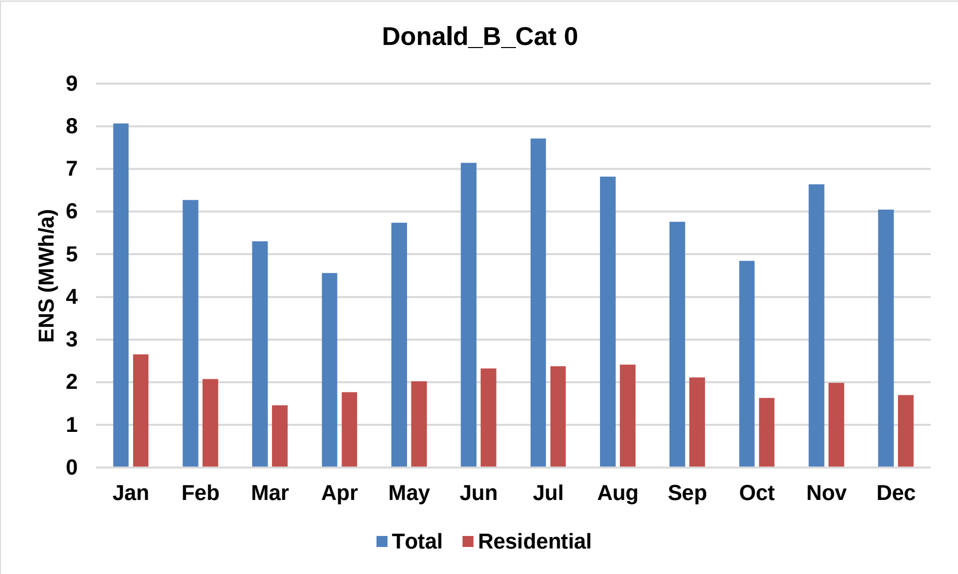


Figure 37: Comparison between total and residential customers for different scenarios (Donald)

5.4.3. Tarnagulla Network: Reliability Analysis' Results

5.4.3.1. Tarnagulla Network: Total Customers

For Tarnagulla area, the similar method is used as Donald analysis. For Donald are, category 0 is not affordable due to higher cost of energy (see **Table 51** and **Table 53**). Therefore, the operation of the microgrid will be more constable for the customers and in fact, it is an impossible category. Based on the limitation criteria in terms of COE, the reliability of Tarnagulla system is applicable for both scenarios with categories 0 and 1. The results for the Tarnagulla are by considering the reliability assessment's security and generation adequacy criteria is presented as **Table 23** to **Table 34** as long as **Figure 38** to **Figure 48**.

Table 23: The LPENS at different load points with all scenarios (Tarnagulla: Total customers)

Load points &	Sc. A (Cat. 0 and 1)	Sc. B (Cat. 0 and 1)

Indices		
Load(LV1)	0.141384	0.150249
Load(LV10)	0.262251	0.278695
Load(LV11)	0.228737	0.24308
Load(LV12)	0.228737	0.24308
Load(LV2)	0.145025	0.154118
Load(LV3)	0.219892	0.233681
Load(LV4)	0.219892	0.233681
Load(LV5)	0.280815	0.298423
Load(LV6)	0.280815	0.298423
Load(LV7)	0.282067	0.299754
Load(LV8)	0.282067	0.299754
Load(LV9)	0.262251	0.278695

Table 24: The load point interruption indices for all scenarios (Tarnagulla: Total customers)

Load points & Indices	LPIF (1/a)	LPIT (h/a)	ACIF (1/a)	ACIT (h/a)	TCIF (C/a)	TCIT (Ch/a)
Load(LV1)	2.156202	6.387594	2.156202	6.387594	2.156202	6.387594
Load(LV10)	2.519811	11.84828	2.519811	11.84828	2.519811	11.84828
Load(LV11)	2.409168	10.33412	2.409168	10.33412	2.409168	10.33412
Load(LV12)	2.409168	10.33412	2.409168	10.33412	2.409168	10.33412
Load(LV2)	2.162619	6.552087	2.162619	6.552087	2.162619	6.552087
Load(LV3)	2.389295	9.93454	2.389295	9.93454	2.389295	9.93454
Load(LV4)	2.389295	9.93454	2.389295	9.93454	2.389295	9.93454
Load(LV5)	2.563088	12.68697	2.563088	12.68697	2.563088	12.68697
Load(LV6)	2.563088	12.68697	2.563088	12.68697	2.563088	12.68697
Load(LV7)	2.568728	12.74353	2.568728	12.74353	2.568728	12.74353
Load(LV8)	2.568728	12.74353	2.568728	12.74353	2.568728	12.74353
Load(LV9)	2.519811	11.84828	2.519811	11.84828	2.519811	11.84828

8. Scenario A with categories 0 and 1

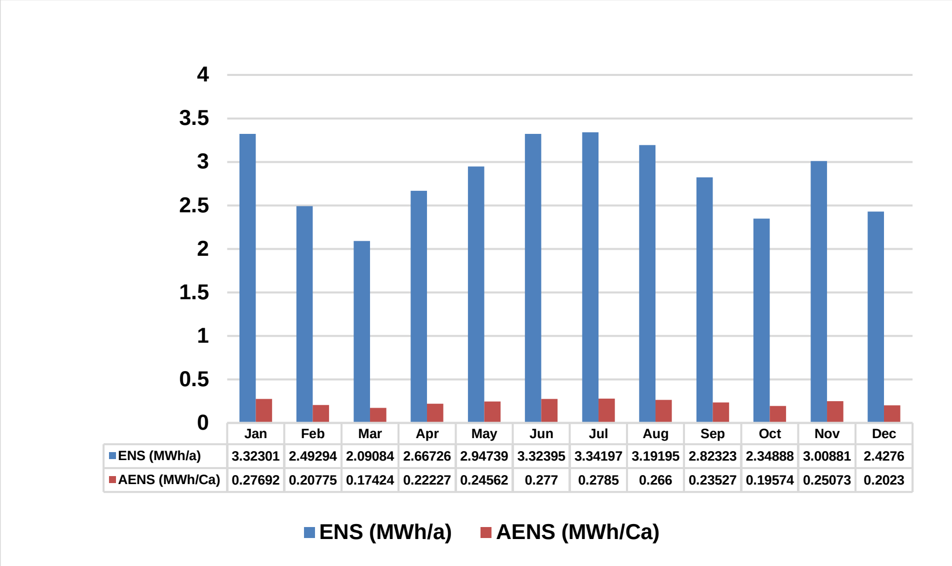


Figure 38: The ENS and AENS under scenario A with categories 0 and 1 (Tarnagulla: Total customers)

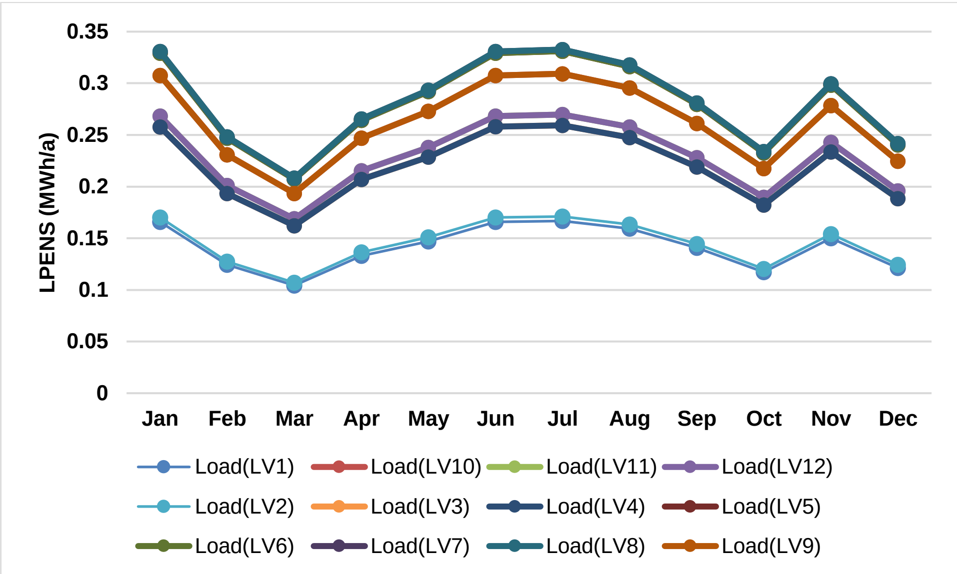


Figure 39: The LPENS under scenario A with categories 0 and 1 (Tarnagulla: Total customers)

9. Scenario B with categories 0 and 1

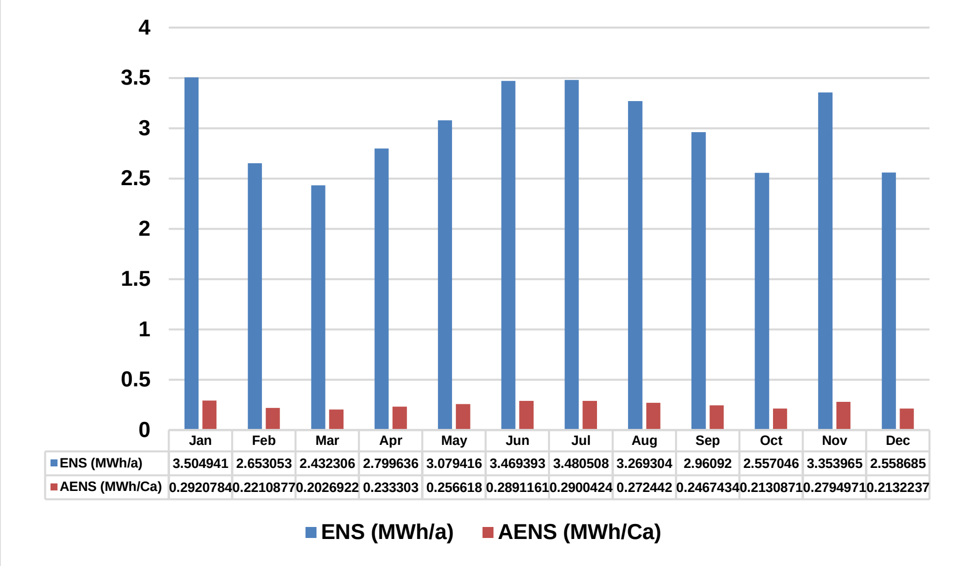


Figure 40: The ENS and AENS under scenario B with categories 0 and 1 (Tarnagulla: Total customers)

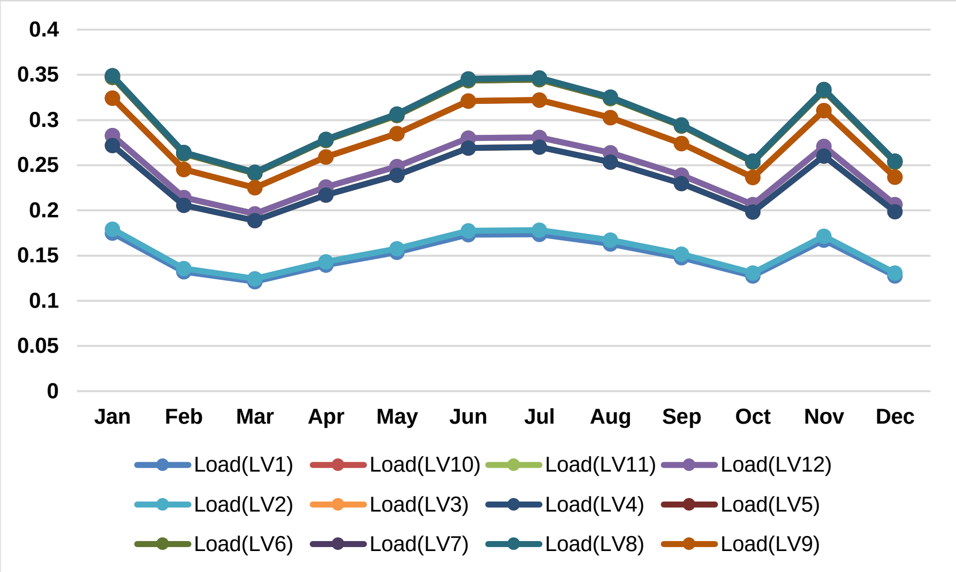


Figure 41: The LPENS under scenario B with categories 0 and 1 (Tarnagulla: Total customers)

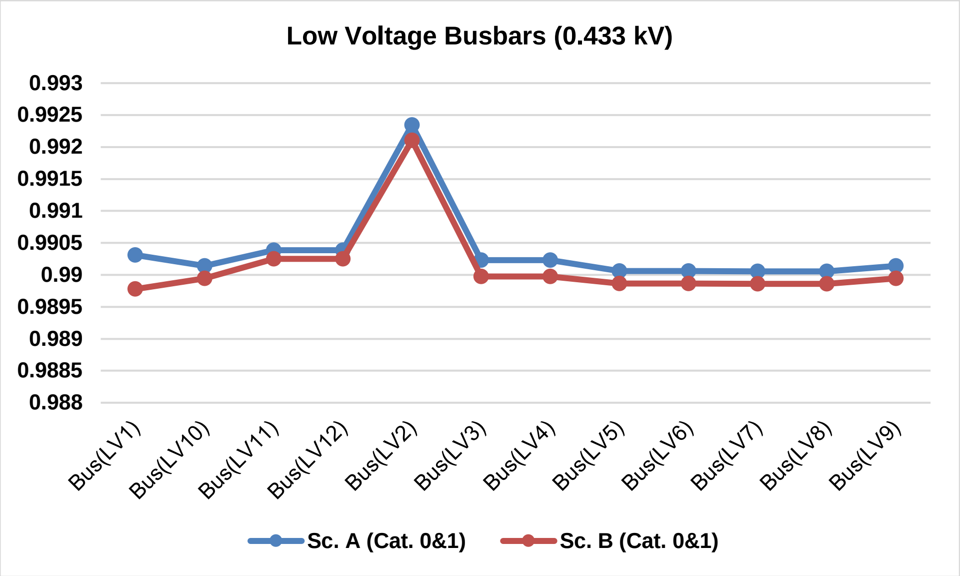
Table 25: The reliability indices with different scenarios (Tarnagulla: Total customers)

Scenarios & Indices	SAIFI (1/Ca)	CAIFI (1/Ca)	SAIDI (h/Ca)	CAIDI (h)	ENS (MWh/a)	AENS (MWh/Ca)	ASIFI (1/a)	ASIDI (h/a)
Sc. A (Cat. 0 and 1)	2.434917	2.434917	10.66955	4.381894	2.833933	0.236161	2.434917	10.66955
Sc. B (Cat. 0 and 1)	2.434917	2.434917	10.66955	4.381894	3.011632	0.250969	2.434917	10.66955

Table 26: The load flow analysis under different scenarios (Tarnagulla: Total customers)

	Generation	Consumption	Loss

Scenarios & Indices	P (kW)	Q (kVAr)	P (kW)	Q (kVAr)	P (kW)	Q (kVAr)
Sc. A (Cat. 0 and 1)	227.6726	146.5752	227.5262	141.7488	0.146213	4.827831
Sc. B (Cat. 0 and 1)	239.9581	154.7669	239.8119	149.4029	0.145969	5.365874



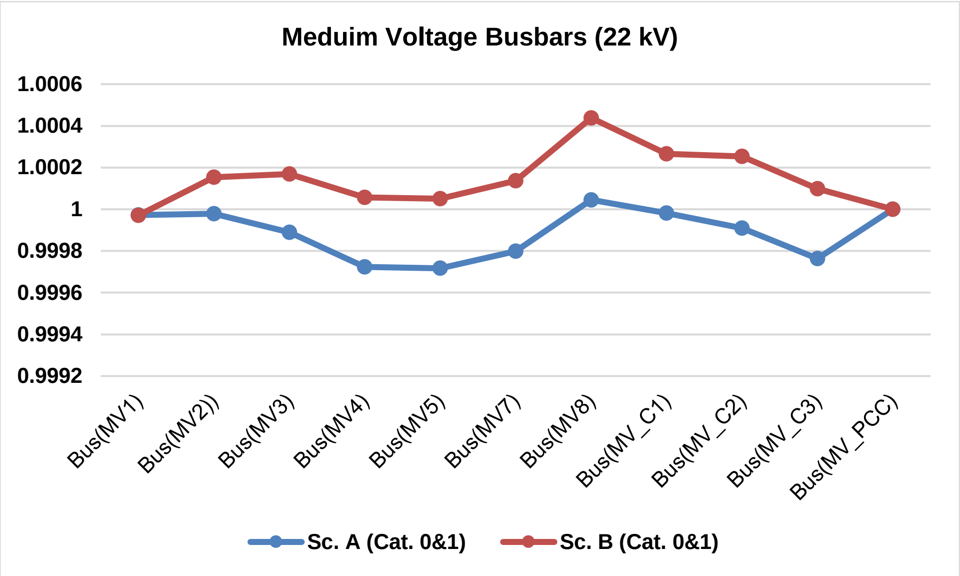


Figure 42: The voltages of different busbars for all scenarios (Tarnagulla: Total customers)

5.4.3.2. Tarnagulla Network: Residential Customers

Table 27: The LPENS at different load points with all scenarios (Tarnagulla: Residential customers)

Load points & Indices	Sc. A (Cat. 0 and 1)	Sc. B (Cat. 0 and 1)
Load(LV1)	0.119874	0.119874
Load(LV10)	0.222353	0.222353
Load(LV11)	0.193937	0.193937
Load(LV12)	0.193937	0.193937
Load(LV2)	0.122961	0.122961
Load(LV3)	0.186438	0.186438
Load(LV4)	0.186438	0.186438
Load(LV5)	0.238092	0.238092
Load(LV6)	0.238092	0.238092
Load(LV7)	0.239154	0.239154
Load(LV8)	0.239154	0.239154
Load(LV9)	0.222353	0.222353

Table 28: The load point interruption indices for all scenarios (Tarnagulla: Residential customers)

Load points & Indices	LPIF (1/a)	LPIT (h/a)	ACIF (1/a)	ACIT (h/a)	TCIF (C/a)	TCIT (Ch/a)
Load(LV1)	2.156202	6.387594	2.156202	6.387594	2.156202	6.387594
Load(LV10)	2.519811	11.84828	2.519811	11.84828	2.519811	11.84828
Load(LV11)	2.409168	10.33412	2.409168	10.33412	2.409168	10.33412
Load(LV12)	2.409168	10.33412	2.409168	10.33412	2.409168	10.33412
Load(LV2)	2.162619	6.552087	2.162619	6.552087	2.162619	6.552087
Load(LV3)	2.389295	9.93454	2.389295	9.93454	2.389295	9.93454
Load(LV4)	2.389295	9.93454	2.389295	9.93454	2.389295	9.93454
Load(LV5)	2.563088	12.68697	2.563088	12.68697	2.563088	12.68697
Load(LV6)	2.563088	12.68697	2.563088	12.68697	2.563088	12.68697
Load(LV7)	2.568728	12.74353	2.568728	12.74353	2.568728	12.74353
Load(LV8)	2.568728	12.74353	2.568728	12.74353	2.568728	12.74353
Load(LV9)	2.519811	11.84828	2.519811	11.84828	2.519811	11.84828

10.Scenario A with categories 0 and 1

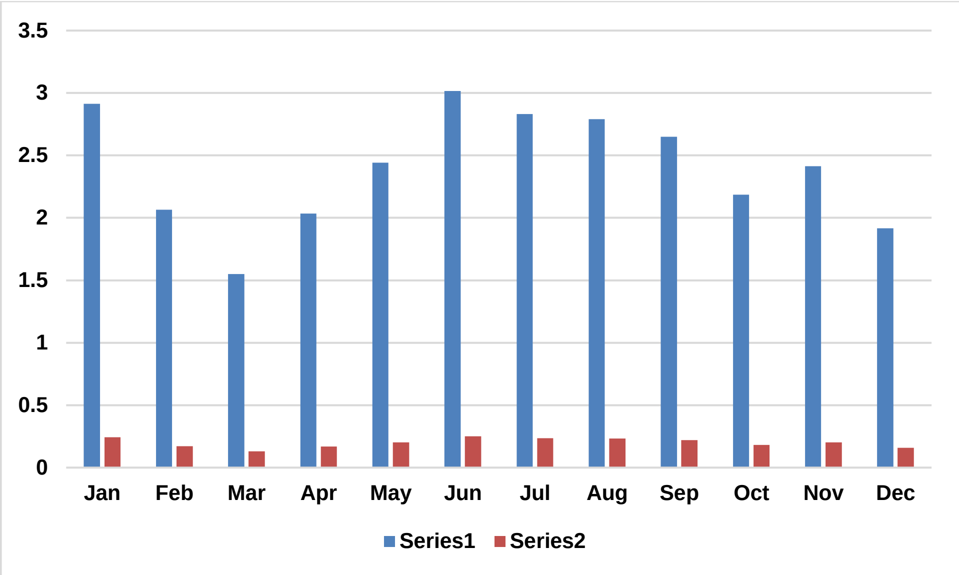


Figure 43: The ENS and AENS under scenario A with categories 0 and 1 (Tarnagulla: Residential customers)

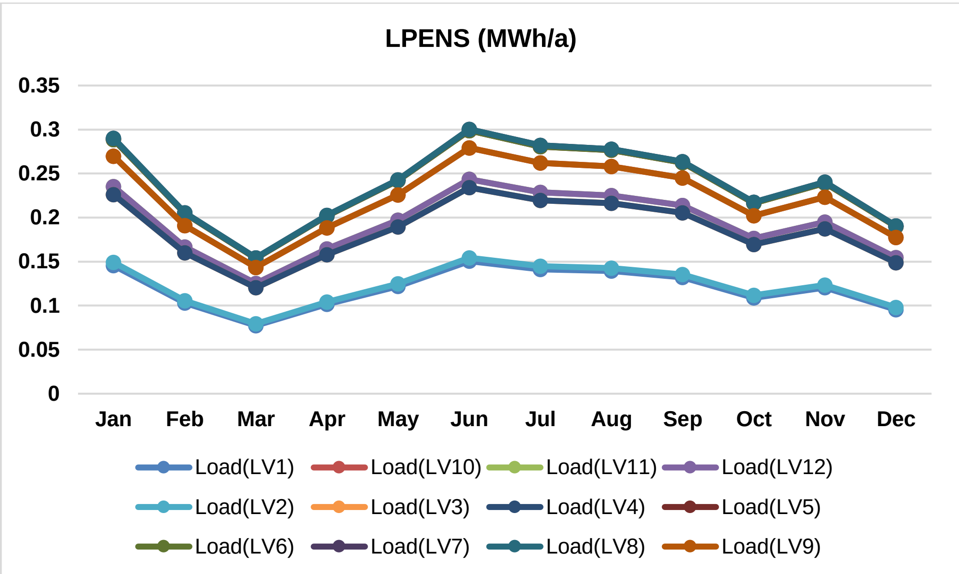


Figure 44: The LPENS under scenario A with categories 0 and 1 (Tarnagulla: Residential customers)

11.Scenario B with categories 0 and 1

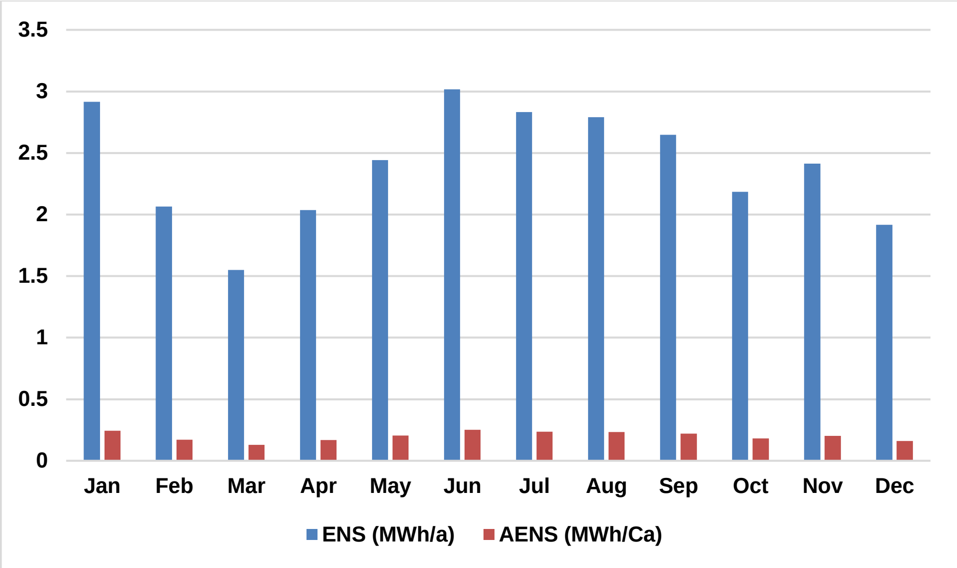


Figure 45: The ENS and AENS under scenario B with categories 0 and 1 (Tarnagulla: Residential customers)

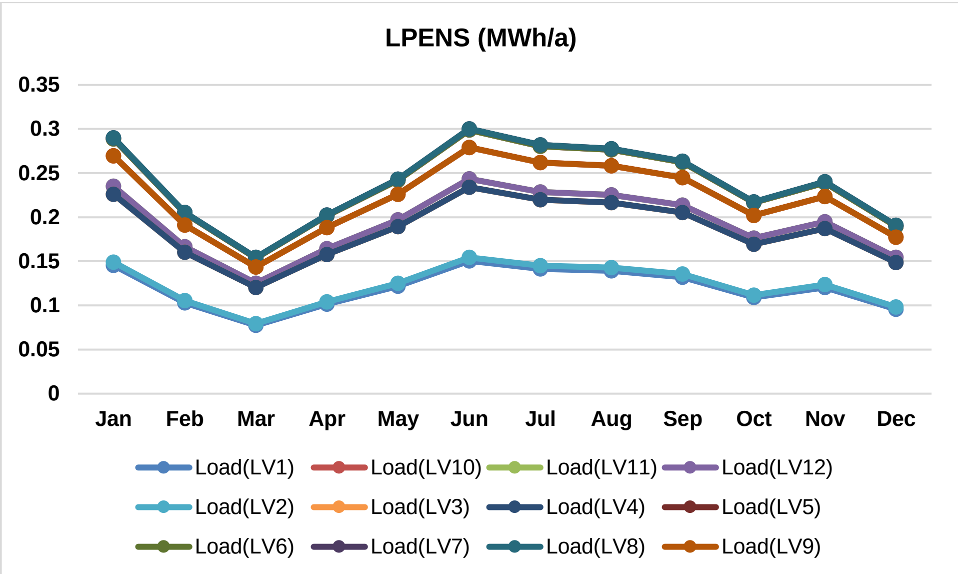


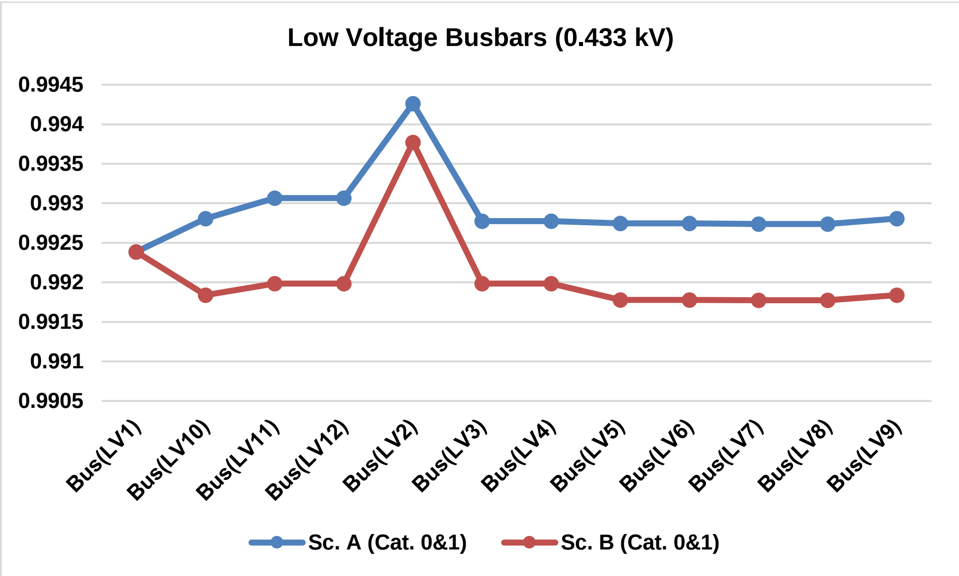
Figure 46: The LPENS under scenario B with categories 0 and 1 (Tarnagulla: Residential customers)

Table 29: The reliability indices with different scenarios (Tarnagulla: Residential customers)

Scenarios & Indices	SAIFI (1/Ca)	CAIFI (1/Ca)	SAIDI (h/Ca)	CAIDI (h)	ENS (MWh/a)	AENS (MWh/Ca)	ASIFI (1/a)	ASIDI (h/a)
Sc. A (Cat. 0 and 1)	2.434917	2.434917	10.66955	4.381894	2.402782	0.200232	2.434917	10.66955
Sc. B (Cat. 0 and 1)	2.434917	2.434917	10.66955	4.381894	2.402782	0.200232	2.434917	10.66955

Table 30: The load flow analysis under different scenarios (Tarnagulla: Residential customers)

	Generation		Consumption		Loss	
Scenarios & Indices	**P (kW)**	**Q (kVAr)**	**P (kW)**	**Q (kVAr)**	**P (kW)**	**Q (kVAr)**
Sc. A (Cat. 0 and 1)	179.824	114.9289	179.6364	111.9135	0.187437	3.016036
Sc. B (Cat. 0 and 1)	179.7403	114.9166	179.6364	111.9135	0.103712	3.003702



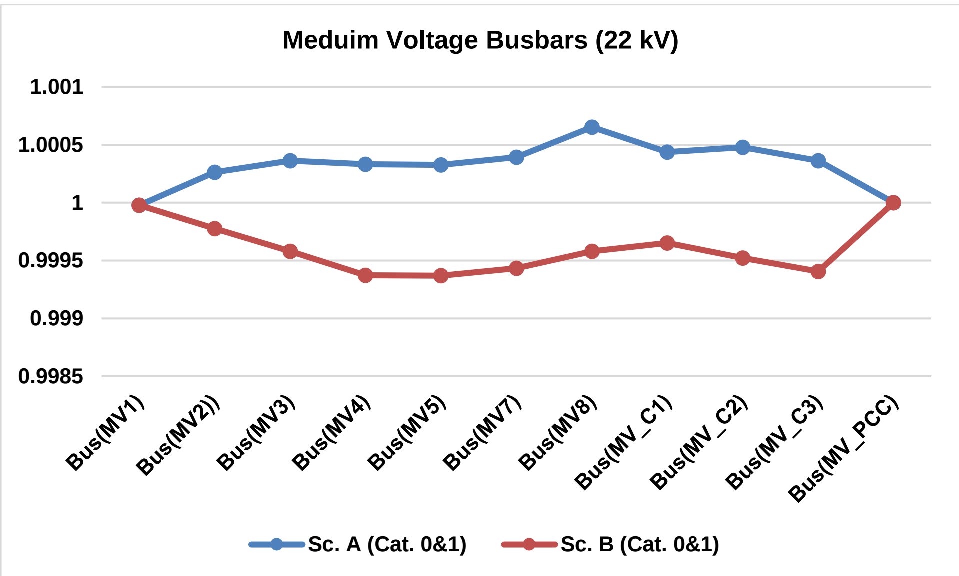


Figure 47: The voltages of different busbars for all scenarios (Tarnagulla: Residential customers)

5.4.3.3. Generation Adequacy Results: Tarnagulla Network

Table 31: Generation adequacy analysis under scenario A with categories 0 and 1 (Tarnagulla: Total customers)

Reliability Indices	Index	PV + DG + Battery	PV + Battery
Loss of Load Probability (%)	Average (LOLP)	0	0
	Lower Confidence Level	0	0
	Upper Confidence Level	0	0
Expected Demand Not Supplied (kW)	Average (EDNS)	0	0
	Lower Confidence Level	0	0
	Upper Confidence Level	0	0
Costs	Lower NPC ($)	4.31M	12.7M
	Lower COE ($/kWh)	0.381	1.12

Table 32: Generation adequacy analysis under scenario A with categories 0 and 1 (Tarnagulla: Residential customers)

Reliability Indices	Index	PV + DG + Battery	PV + Battery
Loss of Load Probability (%)	Average (LOLP)	0	0
	Lower Confidence Level	0	0
	Upper Confidence Level	0	0
Expected Demand Not Supplied (kW)	Average (EDNS)	0	0
	Lower Confidence Level	0	0
	Upper Confidence Level	0	0

Table 33: Generation adequacy analysis under scenario B with categories 0 and 1 (Tarnagulla: Total customers)

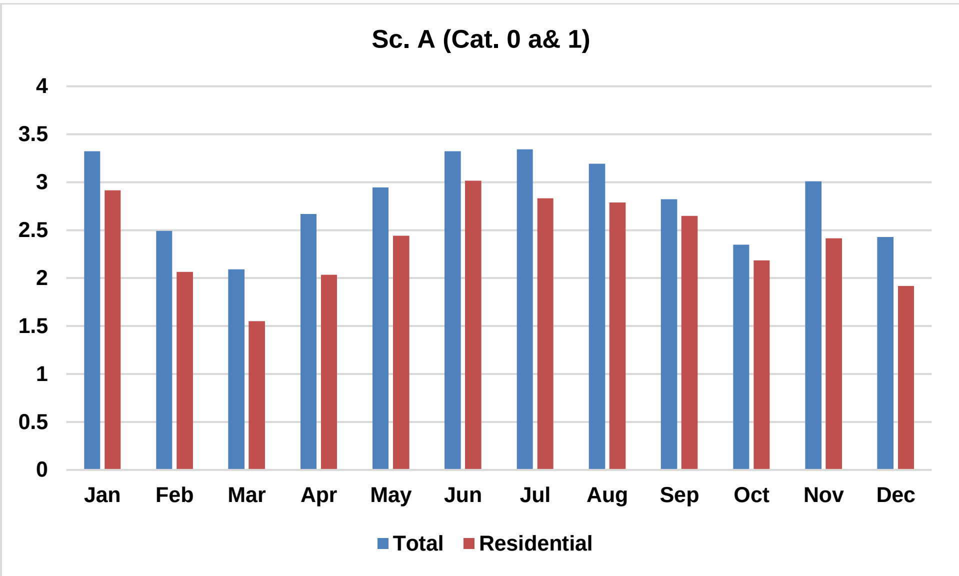
Reliability Indices	Index	PV + DG + Battery	PV + Battery
Loss of Load Probability (%)	Average (LOLP)	0	0
	Lower Confidence Level	0	0
	Upper Confidence Level	0	0
Expected Demand Not Supplied (kW)	Average (EDNS)	0	0
	Lower Confidence Level	0	0
	Upper Confidence Level	0	0

Costs	Lower NPC ($)	4.66M	11.8M
	Lower COE ($/kWh)	0.378	0.956

Table 34: Generation adequacy analysis under scenario B with categories 0 and 1 (Tarnagulla: Residential customers)

Reliability Indices	Index	PV + DG + Battery	PV + Battery
Loss of Load Probability (%)	Average (LOLP)	0	0
	Lower Confidence Level	0	0
	Upper Confidence Level	0	0
Expected Demand Not Supplied (kW)	Average (EDNS)	0	0
	Lower Confidence Level	0	0
	Upper Confidence Level	0	0

5.4.3.4. Comparison between the total and residential customers: Tarnagulla network



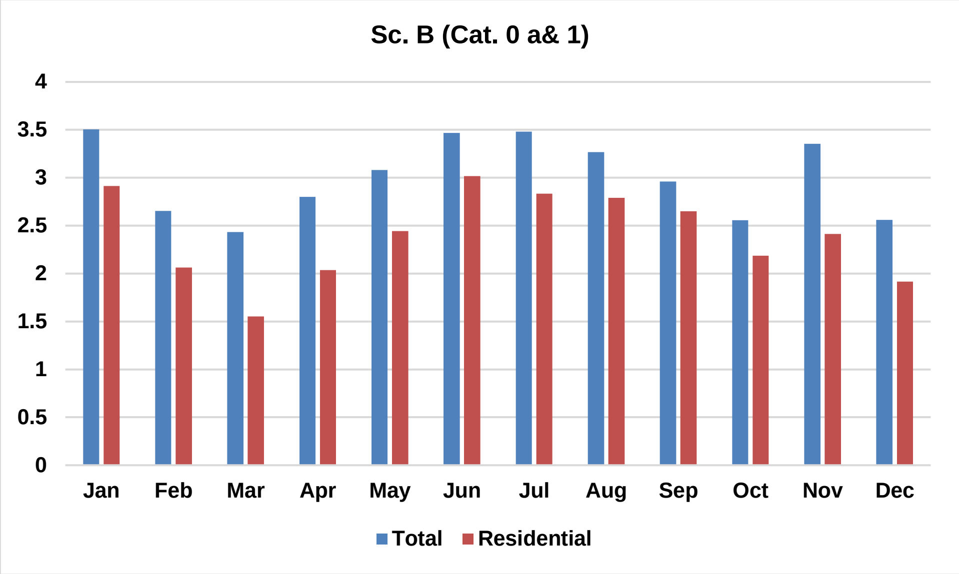


Figure 48: Comparisons between residential and total customers with different scenarios (Tarnagulla)

5.5. Conclusions

1. Based on an overall analysis by taking into account the **techno-economic analysis**, the **power quality and reliability assessment** and **sustainability assessment** (measured by *higher renewable energy fraction*), the installation of PV/Battey/DG is the most optimal integration for the community.
   a. For this configuration, in an optimal microgrid design, if the Donald area is isolated from the utility grid due to outages, the COE will be $0.323/kWh (see **Table 44**).
   b. For this configuration, in an optimal microgrid design, if the Tarnagulla area is isolated from the utility grid due to outages, the COE will be $0.381/kWh (see **Table 49**).
2. The selection of 100% renewable fraction (i.e. the integration of PV/Battery without considering DGs) is not economical (see **Appendix A**) due to the significantly higher CAPEX, resulting in an increase of between 253% and 294% for Tarnagulla and an increase of between 324% and 331% for Donald.
3. There is a clear trade-off between cost, power quality and reliability, and sustainability. We choose to *prioritise on **power quality and reliability** as the criterion with highest priority*. In order to further reduce the cost, we consider load prioritisation and have defined three levels of load criticality: **Community critical (Cat. 0)**, **Medium-flexibility (Cat. 1)** and **High-flexibility (Cat. 2)**.
4. For a smaller microgrid size to reduce the Net Present Cost (NPC), the community can choose to guarantee the power quality and reliability for the Critical load only. For a medium-sized microgrid with a higher NPC, the community can guarantee the power quality and reliability for both the Community critical load and the Medium-flexibility load. For instance, for **Donald-Scenario A**, the NPC of a microgrid to adequately supply **both Cat. 0 and Cat. 1** is **$38.2M** vs the NPC of **$5.84M** for a microgrid to adequately supply **only Cat. 0** (with the respective **initial capital costs** being **$6.08M** vs **$1.17M**). See **Tables 45** and **46** for details.
5. Due to a range of issues, we can only carry out what-if analyses on a number of hypothetical scenarios based on some estimations of the loads in different categories. More specifically, in this project, we analyse the two cases: (i) **low** proportions of the loads are *Community critical* and *Medium-flexibility* (**Scenario A**), and (ii) **high** proportions of the loads are *Community critical* and *Medium-flexibility* (**Scenario B**). These two scenarios represent the two estimated extremes of the loads in the community where the proportions of community critical loads are at the lower vs higher end of the total load. Other scenarios can be considered to be between

these two extremes. Thus, the community can expect that the costs would not be lower than those obtained in the analyses for **scenario A** and they should not be higher than those obtained in the analyses in **scenario B**.

6. The power quality and reliability assessment has been conducted in DIgSILENT Power Factory in terms of **Security Assessment** and **Generation Adequacy Assessment** for which the key results are presented as follows:
   A. **In Terms of Security Assessment:**
      a. If the Donald area completely operates in islanded operation mode by isolating from the utility grid for entire year, the average number of power outage will be 2.7 with the total duration of 14.7 hours. To put this into the perspective of the current distribution network for the Donald area (CTN006): In the three years between 2018 and 2020, the network experienced eight (8) power outages due to high-voltage (HV) faults with an average duration of 9.38 minutes per outage. These are the situations in which a community microgrid will be able to ensure continuing supply of electricity to the designated loads by seamless transition from the grid-connected mode to an islanding mode of operation. Assuming the independence of the two events: transmission/distribution network outage and microgrid outage, the chance for a designated load in the microgrid not to be supplied is about 0.000008%. That is, the power security and reliability for a designated load is approximately 99.999992%. Further details of the assessment in terms of energy not supplied (ENS) for different types of customers can be found in the reports (refer to **Figures 21, 23, 25, 27, 30, 32, 34** and **Table 13 and Table 17**)
      b. If theTarnagulla area completely operates in islanded operation mode by isolating from the utility grid for the entire year, the average number of power outage will be 2.43 with the total duration of 10.67 hours. To put this into the perspective of the current distribution network for the Tarnagulla area (MRO007): In the three years between 2018 and 2020, the network experienced eleven (11) power outages due to high-voltage (HV) faults with an average duration of 50.2 minutes per outage. Again, by assuming the independence of the two events: transmission/distribution network outage and microgrid outage, the power security and reliability for a designated load is approximately 99.999957%. Further details of the assessment in terms of energy not supplied (ENS) for different types of customers can be found in the reports (refer to **Figures 38, 40, 43** and **Tables 25, 42, 44 and 29**)
   B. In Terms of Generation Adequacy Assessment:
      a. If the Donald region is isolated from the utility grid and the community only get access to electricity through the installed PVs, batteries, and DGs, it is demonstrated that the installed capacities are capable of serving loads continuously during the days and nights regardless of the weather condition (i.e., even when there is insufficient solar radiation for the PVs to generate large amount of electricity) under the assumption that there is sufficient diesel fuel for the diesel gensets to be run at or near maximum capacity. Note that the generation adequacy assessment is a critical in-depth analysis into the issue of power security and reliability in the microgrids when comparing to the analyses carried out in Project 49.05 as it is particularly important for situations in which the microgrid needs to operate in islanding mode during extreme weather events (e.g., on a very hot/very cold day). It provides the necessary assurance of power security for the community within the provided parameters.
      b. Similarly, it has been shown that, if the Tarnagulla region is isolated from the utility grid and the community only gets access to electricity through the installed PVs, batteries, and DGs, the installed capacities are capable of serving loads continuously during the days and nights regardless of the weather condition.

7. It is also important to note that: While there will be significant capital investments to install the microgrids in these areas, the customers will be able to recover most (if not all) of these costs due to the generation of renewable energy through the installed PVs and batteries. A more detailed analyses will require forecast of electricity prices in the future which is beyond the scope of this project.

While a categorisation of customers into one of the three categories depending on the criticality of the customer's load does give us a useful mechanism for performing what-if analyses to provide important insights into the costs and benefits (in terms of power security and power quality and reliability) that a microgrid would bring to a community, such a categorisation is insufficiently fine-grained to provide an answer to another quite important question: "*what is the flexibility a customer can have regarding the supply security for the different loads in their household or at their business?"* The next section is our attempt to address this concern given our limited access to a detailed customers' appliance model and preference profiles.

6. TASK 2: Customer's flexibility regarding supply security

This section presents the results and insights produced in Task 2 of this project. We employ a model-based market-driven approach (presented in subsection 6.1) for investigating and finding an answer to the important question: "*what is the flexibility a customer can have regarding the supply security for the different loads in their household or at their business?"*.

6.1 Methodology

We assume that the microgrid is managed by a single entity (called the *microgrid operator* – **MGO**) who has full control of the microgrids generation capabilities (PVs, diesel gensets) and batteries as well as the microgrid control system (MGCS). We also assume that, when in island mode of operation, the microgrid provides sufficient on-site power generation that supports facility operations indefinitely for the designated loads, until utility service can be restored. When in island mode of operation, costly generation options such as diesel gensets may need to operate if the demand cannot be met by the generation of the PVs and the battery (especially at night, or during cloudy days). Subsequently, we make the assumption that a **cost function *C(Q; t)* that specifies the cost for the MGO to provide *Q* amount of power to the customers at time *t* for the day under consideration** is given. Here we assume that the cost function *C(Q; t)* is convex increasing in *Q* for each *t* due to the high cost incurred by running expensive gensets such as the diesel generators. The MGO sets the price vector *p(t)* for each time *t* of the day. The MGO can set price according to different pricing schemes, including fixed-price, time of use (TOU) or dynamic pricing. We also assume that each customer operates a set of appliances such as air conditioner, refrigerator, electric vehicle, lighting, washing machine, entertainment units. For each appliance of a customer, we assume a utility function *U(q)* that quantifies the utility this customer obtains when it consumes *q(t)* power at each time *t*; and a set of constraints governing the usage of the appliance.

Given the price vector *p(t)* set by the MGO, a customer aims to maximize their own benefit:

$$\max_q \sum_a U(q_a) - \sum_t p(t)Q(t)$$

(subject to the above constraints over the appliances *a*)

On the other hand, knowing that the customers' energy consumption will be influenced by the price, the MGO aims to set the price *p(t)* so that: (i) the customers' payment will recover the costs incurred to supply sufficient electricity to meet the customers' demand, and (ii) the **total customers' benefits will be maximized** (i.e., **welfare maximization**).

To realise an appropriate and optimal dynamic pricing scheme such that both the objectives of the customers and the MGO can be met, we develop a **prototype market platform**. The key idea behind the **market mechanism** is that it allows the MGO to set the electricity price at the equilibrium of demand and supply. The *market mechanism* works like an **automated multi-round negotiation** between the MGO and the software agents representing the customers (one agent for each customer):

One of the typical termination criteria of the above iterative process is when there is no change in the customers' demand showing that the price set at the termination round is at the equilibrium of supply and demand and no customer can gain by having a different energy consumption for the day. The underlying idea behind the below algorithm is as follows: Given the customers' proposed energy consumption over the next day, the MGO can compute the cost to supply that total energy consumption (based on the cost function $C(Q; t)$) and the corresponding price vector $p(t)$. As the customers receives the pricing signal, they may choose to **consume more** (*if the price is considered to be lower than the utility gains they would get by consuming more*) or **less** (*if the price is considered to be higher than the utility they get for their proposed consumption*). The updated energy consumption is sent back to the MGO and the process repeats until termination condition is satisfied.

The market mechanism can be summarised as follows:

In the first round (Round 0):

- The MGO set the initial price vector $p^0(t)$ [$p^0(t)$ can be set based on historical smart meter data of the customers' energy consumption];

For each subsequent round k: ($k > 0$)

- The MGO broadcast the price vector $p^{k-1}(t)$ to all customers.
- Based on this price vector $p^{k-1}(t)$, each customer will calculate their own electricity usage for each time t of the day; then, the customers' demand will be sent back to the MGO;
- Based on the customers' aggregate demand, the MGO calculates the new price vector $p^k(t)$

To illustrate the usage of the market platform and to demonstrate the benefits of a dynamic pricing-based demand response program, we also create a hypothetical scenario with a MGO's electricity cost function (see **Figure 49**). Observe that we assume that the cost function does not change over different times of the day.

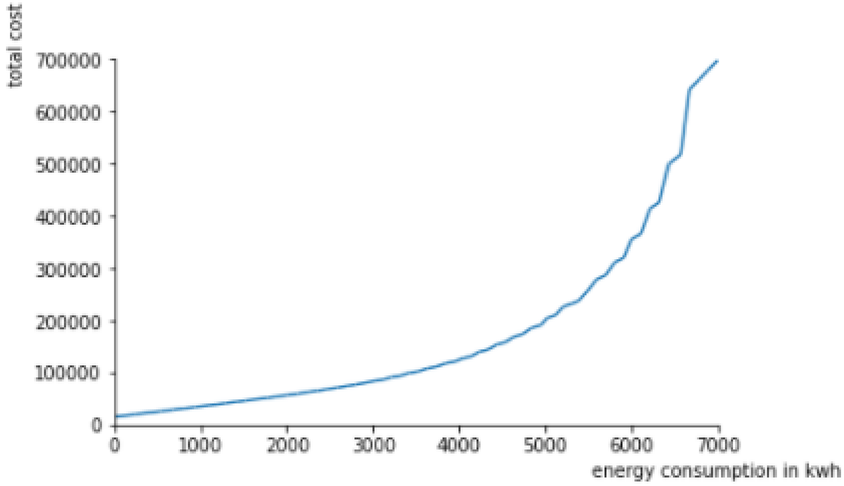


Figure 49: A hypothetical energy cost function *C(Q; t)* for electricity supply

To analyse the hypothetical scenario, we simulate 16 different customer types with various appliances and corresponding utility functions based on our early analysis of various appliance models and their respective utility functions (cf. [14]). The model was specifically developed for a community-based residential microgrid with realistic appliance models. This hypothetical model is our attempt, *in the absence of the preference profiles of the customers in Donald and Tarnagulla*, to re-create a realistic preference profiles for customers in a community-based residential microgrid.

6.2 Results

We have tested the prototype market platform and it worked well on the test cases performed. The prototype market platform is implemented in Python and will be made available as a Jupyter Notebook. The main input into the simulator (to enable what-ifs analysis) is the energy cost function *C(Q; t)* and the customers' preference profiles $U(q_a)$. Both require significant modelling effort. In particular, we expect that **Project 49.02** (**Community Engagement**) will provide the customers' preference profiles and **Project 49.05** (**Islanding Design and Cost Analysis**) will provide the energy cost function for the islanding scenarios. In the hypothetical scenario for which we perform the analysis to demonstrate the developed market platform, we employ the model of energy cost function described in **Figure 50** which is visualised in **Figure 49**:

```
formula  # the uneven accleration of the 2nd de
```

Out[2]:

$$
\begin{cases}
20x + 15000 & \text{for } x < 0 \\
0.0001x^2 + 20x + 15000 & \text{for } x \leq 200 \\
0.00012x^2 + 20x + 15000 & \text{for } x \geq 200 \wedge x \leq 400 \\
0.00014x^2 + 20x + 15000 & \text{for } x \geq 400 \wedge x \leq 600 \\
0.00016x^2 + 20x + 15000 & \text{for } x \geq 600 \wedge x \leq 800 \\
0.00018x^2 + 20x + 15000 & \text{for } x \geq 800 \wedge x \leq 1000 \\
0.0002x^2 + 20x + 15000 & \text{for } x \geq 1000 \wedge x \leq 1200 \\
0.00025x^2 + 20x + 15000 & \text{for } x \geq 1200 \wedge x \leq 1400 \\
0.0003x^2 + 20x + 15000 & \text{for } x \geq 1400 \wedge x \leq 1600 \\
0.00035x^2 + 20x + 15000 & \text{for } x \geq 1600 \wedge x \leq 1800 \\
0.0004x^2 + 20x + 15000 & \text{for } x \geq 1800 \wedge x \leq 2000 \\
0.00045x^2 + 20x + 15000 & \text{for } x \geq 2000 \wedge x \leq 2200 \\
0.00055x^2 + 20x + 15000 & \text{for } x \geq 2200 \wedge x \leq 2400 \\
0.00065x^2 + 20x + 15000 & \text{for } x \geq 2400 \wedge x \leq 2600 \\
0.00075x^2 + 20x + 15000 & \text{for } x \geq 2600 \wedge x \leq 2800 \\
0.00085x^2 + 20x + 15000 & \text{for } x \geq 2800 \wedge x \leq 3000 \\
0.00095x^2 + 20x + 15000 & \text{for } x \geq 3000 \wedge x \leq 3200 \\
0.00115x^2 + 20x + 15000 & \text{for } x \geq 3200 \wedge x \leq 3400 \\
0.00135x^2 + 20x + 15000 & \text{for } x \geq 3400 \wedge x \leq 3600 \\
0.00155x^2 + 20x + 15000 & \text{for } x \geq 3600 \wedge x \leq 3800 \\
0.00175x^2 + 20x + 15000 & \text{for } x \geq 3800 \wedge x \leq 4000 \\
0.00195x^2 + 20x + 15000 & \text{for } x \geq 4000 \wedge x \leq 4200 \\
0.00225x^2 + 20x + 15000 & \text{for } x \geq 4200 \wedge x \leq 4400 \\
0.00255x^2 + 20x + 15000 & \text{for } x \geq 4400 \wedge x \leq 4600 \\
0.00285x^2 + 20x + 15000 & \text{for } x \geq 4600 \wedge x \leq 4800 \\
0.00315x^2 + 20x + 15000 & \text{for } x \geq 4800 \wedge x \leq 5000 \\
0.00355x^2 + 20x + 15000 & \text{for } x \geq 5000 \wedge x \leq 5200 \\
0.00395x^2 + 20x + 15000 & \text{for } x \geq 5200 \wedge x \leq 5400 \\
0.00435x^2 + 20x + 15000 & \text{for } x \geq 5400 \wedge x \leq 5600 \\
0.00485x^2 + 20x + 15000 & \text{for } x \geq 5600 \wedge x \leq 5800 \\
0.00535x^2 + 20x + 15000 & \text{for } x \geq 5800 \wedge x \leq 6000 \\
0.0061x^2 + 20x + 15000 & \text{for } x \geq 6000 \wedge x \leq 6200 \\
0.0071x^2 + 20x + 15000 & \text{for } x \geq 6200 \wedge x \leq 6400 \\
0.0086x^2 + 20x + 15000 & \text{for } x \geq 6400 \wedge x \leq 6600 \\
0.0111x^2 + 20x + 15000 & \text{for } x > 6600
\end{cases}
$$

Figure 50: The hypothetical energy cost function *C(Q; t)* for electricity supply as an input to the Python notebook

For the above hypothetical scenario, we conduct a detailed analysis to demonstrate the impact of dynamic pricing on customer's electricity usage. For a random customer, the changes in the customer's energy consumption upon termination of the negotiation process can be observed in **Figure 51**. It can be observed that through the negotiation process, the customer has chosen to curb their energy consumption when facing prices that higher than the utility of consuming the electricity by some of their appliances such as the air conditioner during the period it has the most consumption of energy (i.e. between 12pm and 9pm).

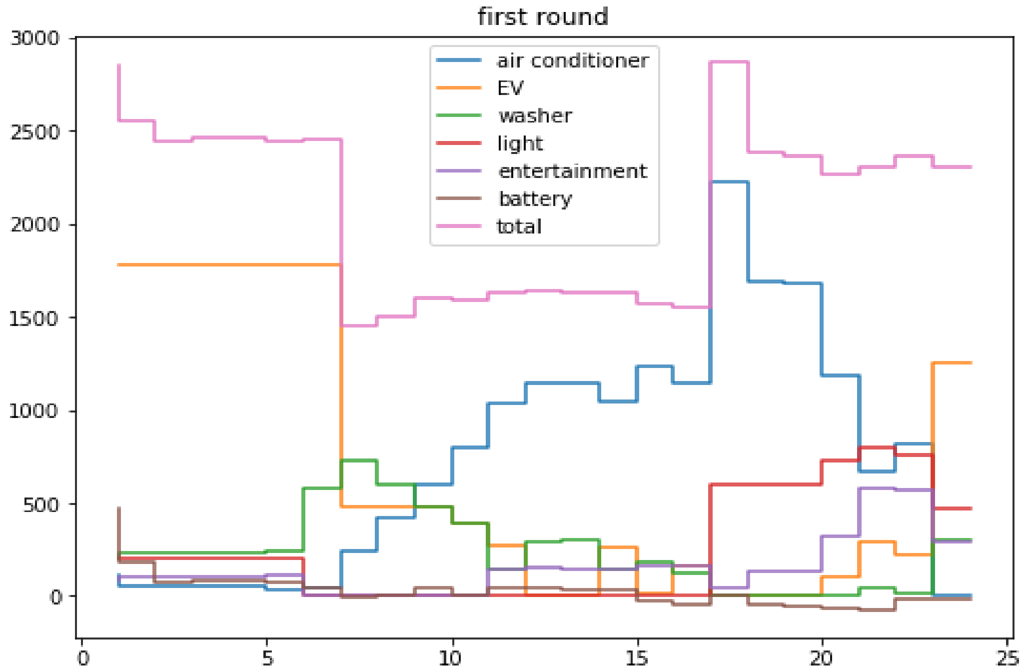


Figure 51 (a)

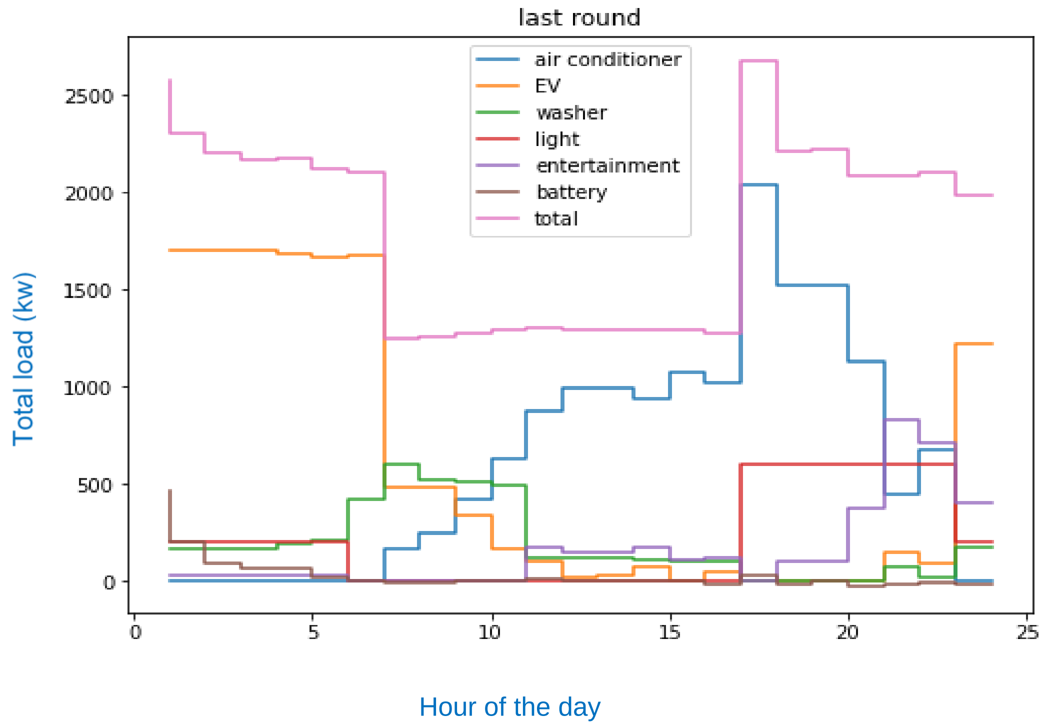


Figure 51 (b)

Figure 51: Changes in a customer's energy consumption induced by dynamic pricing (Observe the peak consumption in the first round is well above 2500)

Furthermore, the effect of dynamic pricing on flattening the peak load for the simulated microgrid can also be observed. In our study, four different pricing strategies have been studied:

1. Fully subsidised energy scheme (the "***don't care price***" strategy): Under this pricing strategy, the customer does not have to pay for the energy they consume and thus will choose to consume the energy so that their appliances utilities will be maximised while ignoring the cost of energy altogether.
2. Flat price scheme 1 (the ***fixed price 1*** strategy): In this scheme, the customer is charged a flat price *p*, such that

$$p = \frac{(1+\Delta)\sum_{t\in\mathcal{T}} C(Q(t),t)}{\sum_{t\in\mathcal{T}} Q(t)}$$

with {*Q(t)*} the best response to such a price from the customers.
3. Flat price scheme 2 (the ***fixed price 2*** strategy): In this scheme we use the information obtained from our proposed dynamic pricing demand response scheme to set a flat price *p*. We collect the price {*p(t)*} according to the dynamic pricing scheme and total power demand {*Q(t)*} information under the dynamic pricing scheme and then set the flat price as

$$p = \frac{\sum_{t\in\mathcal{T}} p(t)\bar{Q}(t)}{\sum_{t\in\mathcal{T}} Q(t)}.$$

4. Dynamic pricing scheme (the ***dynamic price*** strategy):In this scheme, the market mechanism described above is used to determine the real-time price (which is at the equilibrium of supply and demand).

The dynamic pricing scheme can be observed to have flattened the peak load in the microgrid (see **Figure 52**).

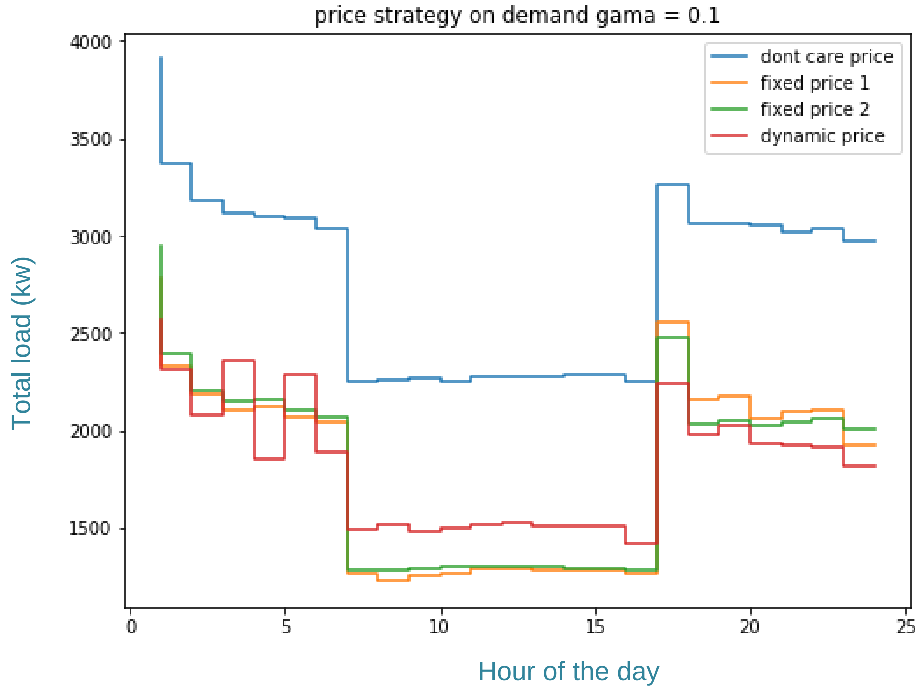


Figure 52: Comparison of the total load over the 24 hours period under different pricing strategies

6.3 Conclusion

Due to the lack of customer's appliance model and preference profiles, we were unable to conduct an in-depth investigation into the customers' flexibility regarding power supply security for the customers in Donald and Tarnagulla. However, we have developed an analysis tool that integrates a market platform to enable a dynamic pricing-based demand response (DR) program for community-based microgrids. A prototype of the tool has been fully developed and run on a hypothetical scenario for a community of customers whose preference profiles are simulated One major based on realistic appliance models in a community-based microgrid [14]. This can be a useful tool to be used by power companies or consultants to provide customers and other stakeholders with comprehensive analysis of the impact of not having a specific load supplied during islanding of the microgrid (by translating such an impact to economic losses/gains). The use of this tool has been demonstrated with the analysis of the hypothetical scenario for the studied community-based microgrid. *Note that this tool will help address a specific comment from Powercor regarding the flexibility of the customer to consider their different loads as being more critical or less critical.*

7. TASK 3: Regulatory requirements on de-energisation and re-energisation of microgrids

As observed by international researchers on policymaking for microgrids, **the regulatory environment into which microgrids are entering is extremely complex, in part because they encroach on multiple areas of existing regulation not conceived with them in mind, i.e., generator interconnection rules, air quality permitting, building codes, tariffication, etc.** Subsequently, most jurisdictions (Australia and Victoria included) are still currently exploring and experimenting with regulatory frameworks for microgrids. In particular, it has been observed [24] that: "*As with many U.S. regulatory issues, interconnection is seriously complicated because utility regulation resides, in large part, at the state level*." This is likely to be applicable to Australia and Victoria as well.

7.1 Review of existing regulations at different levels of governments (state and national)

One major challenge when conducting a review into existing regulations of microgrids by the state and national governments in Australia is the lack of a consistent definition of the terminology "microgrid" used in various regulatory frameworks in Australia. For instance, according to the website of the Department of Environment, Land, Water and Planning (DELWP) of the Victoria State Government [18], "*A microgrid generally operates while connected to the grid however, importantly it can break off and operate on its own using local energy generation. It has a single point of connection with the grid with a monitoring and control platform used to coordinate the supply and demand of the customers connected to the microgrid*." On the other hand, a **review of the regulatory frameworks for microgrids** was initiated by the COAG Energy Council and conducted by AEMC [19] defines microgrids as a type of stand-alone power systems (SAPS) which encompass both microgrids, which supply electricity to multiple customers, and individual power systems, which supply electricity to a single customer. Furthermore, the COAG Energy Council states that the AEMC's **Review of regulatory arrangements for embedded networks** also address a number of issues for customers of stand-alone power systems. Hence, we will also review the applicable regulatory requirements and recommendations for embedded networks in this report.

This review is undertaken for the so-called community microgrids (as opposed to islanded microgrids which operate permanently in the islanded mode). Clearly, the focus of this report will be on the regulatory requirements for re-energising and de-energising of the microgrids and their loads.

The AEMC's ***Review of the regulatory frameworks for stand-alone power systems*** [19] was split into two priority areas:

- priority 1: focussing on the development of a national framework for customers that move from grid-connected supply to stand-alone systems provided by DNSPs; and
- priority 2: focussing on the development of a national framework to support the supply of electricity from stand-alone power systems provided by parties other than DNSPs.

Both priority areas are relevant to this project as the microgrids can be either provided by DNSPs or by parties other than DNSPs (such as the community or a separate microgrid operator). While these Priority reports provide a fairly comprehensive review on regulatory requirements as well as make a number of recommendations, very few are related to re-energising and de-energising of the SAPS and their customers. In particular, these reviews provide comprehensive recommendations in terms of new customers' connection and existing customers' reconnection and disconnection but there were almost no mentions of the regulatory requirements regarding re-energisation and de-energisation. Furthermore, as observed by The Clean Energy Council [22], the AEMC's Reviews have left the most challenging areas of microgrid regulation to the states and territories. For example, regarding the **Reliability standards and other consumer protections**, "*To enable stand-alone customers to receive reliability protections equivalent to grid-connected customers, and on the basis that network reliability standards are the responsibility of the states and territories, the Commission recommends that the jurisdictions review their legislative instruments governing reliability standards and guaranteed service level schemes, and make any required changes.*" Subsequently, we expect that the Victoria government will develop a set of rules and regulations to regulate the installation and operation of microgrids in Victoria. In the following, we will outline some of the challenges in regard to this task and also provide a number of recommendations to be considered by the regulatory bodies to ensure safety, reliability as well as other consumer protections.

The integration of a microgrid on a distribution feeder introduces the bidirectional power flow structure to a power network. Without careful engineering, microgrid penetration can potentially have many adverse system impacts related to **protection**, **control**, **power quality**, **reliability of power supply**, **restoration time after outage** and **operational safety** [20]. These issues become particularly pertinent when the microgrid or some parts of it are being de-energised or re-energised. For instance, works done on some part of the network or on a customer installation are required to be carried out in accordance with Australian Standard 4836:2011 Safe working on or near low-voltage electrical installations and equipment, which generally requires the relevant section of the network or the apparatus to be de-energised during work processes. Such de-energisation needs to be performed by both the operator of the distribution networks and the operator/control system of the microgrid.

Embedded networks can be seen as a simplified version of grid-connected microgrids. They are considered simpler because they are not required to include distributed energy resources (DERs) such as distributed generators and energy storage which are required by microgrids to be able to operate in islanding mode. Thus, most embedded networks is unable to operate in islanding mode and would likely have fewer regulatory requirements in comparison to grid-connected microgrids with islanding capability. However, as discussed in EMTPT's Consultation Paper (**Attachment 1** of [20]), the embedded network framework may be applicable to on-grid microgrids and therefore the regulatory issues identified for embedded networks are likely to be applicable to grid-connected microgrids as well. Furthermore, the regulatory frameworks for embedded networks in Australia and Victoria are also considerably more mature due to their long history and greater penetration. (At the time of the AEMC's publication of the Final Report for ***Updating the regulatory frameworks for embedded networks***, 20 June 2019, there were almost 4,500 embedded electricity networks that had been registered as being exempt from registering as a Network Service Provider with over half a million customers. In particular, at that time, the Commission estimated that in Victoria alone there were approximately 117,000 residential customers connected to registered exempt networks.) Nevertheless, the AEMC's Final Report for ***Updating the regulatory frameworks for embedded networks*** states:

> *While embedded network customers do benefit from some consumer protections imposed by the AER as conditions of exempting embedded network operators from registering as a network service provider and being authorised as a retailer, these consumer protections are more limited than those applicable for standard supply arrangement customers.* ***Consumer protection gaps exist in areas such as de-energisation*** *and* ***re-energisation obligations****, obligations to provide connection services, life support arrangements, information provision and retailer of last resort arrangements.*

One of the critical areas related to de-energisation obligation is life support requirements. Life support requirements are designed to provide additional consumer protections and require retail and distribution businesses to register premises that have a person using life support equipment (for example an oxygen concentrator or kidney dialysis machine) that relies on electricity to operate.

The requirements facilitate the provision of information to parties that need to be aware of life support equipment at a premise, and impose obligations on NEM retailers and DNSPs to provide additional safeguards around de-energisation for consumers using life support equipment that relies on electricity to operate. Within the current arrangements in the NEM, life support obligations are contained in Part 7 of the NERR. Under Part 7, both the distributor and retailer have obligations in relation to life support equipment. These obligations require notification that a person is using life support equipment that relies on electricity at a customer's premises to be provided to both distributors and retailers through a two-way information flow. The life support rules apply to any standard or market retail contract and the key provisions are civil penalty provisions. On the other hand, life support arrangements for customers within embedded networks are much more complicated. Not only do the embedded network customer's direct distributor (i.e. the exempt network service provider), and the customer's direct retailer at the child connection point (i.e. NEM retailer or exempt seller) need to be aware of a person requiring life support equipment at the premises, but the NEM retailer at the parent connection point and the DNSP also need to be made aware of the existence of a customer requiring life support equipment at the premises. If a similar structure is to be employed in a community microgrid, e.g., the microgrid operator will play the role of the microgrid customer's direct distributor with a same or different entity playing the role of the customer's direct retailer at the child connection point, a NEM retailer at the parent connection point and a DNSP, a similarly complicated arrangements will need to be in place for life support arrangements within a microgrid. On the other hand, given the microgrid's ability to provide backup power during planned outages, unplanned outages, blackouts, and load shedding by the DNSP, the obligations of the microgrid operator appear to become much more significant in a microgrid setup.

The AEMC's ***Review of the regulatory frameworks for stand-alone power systems*** [19] observes that:

> *Currently, as SAPS are not (in general) captured under the national regulatory framework, they are subject to jurisdictional frameworks. These jurisdictional frameworks vary in their comprehensiveness, with state and territory regimes differing quite widely. Some states with significant numbers of stand-alone power systems have relatively well-developed regulatory frameworks, but other jurisdictions with no, or relatively few, such systems often do not.*

([19], page 5)

The Review then subsequently emphasizes the importance of a national regulatory framework for SAPS:

> *Given changing technologies, it is important that changes to the national framework are made to allow the uptake of DNSP-led SAPS, where this is efficient.*
>
> *There are a range of reasons that justify the need for effective regulation of SAPS:*
>
> - *Energy is an essential service for which there is a need and expectation for certain minimum protections, but in some jurisdictions SAPS customers currently have no energy-specific consumer protections and minimal safety or reliability standards.*
> - *Once they are established, SAPS may exhibit natural monopoly characteristics such that regulation is required to simulate competitive market outcomes.*
> - *SAPS may be a more efficient alternative to maintaining a traditional regulated DNSP connection in some areas, but customers will not voluntarily install them in*

rural locations where non-locational network pricing means the costs faced by the customer would increase.

- *Regulatory barriers may inhibit new entrant products and services that have potential to benefit consumers and increase energy productivity.*

Amendments to the NEL and NER, and the NERL and NERR, would allow DNSPs to provide off-grid supply via SAPS as a distribution service, with conditions to protect customers and enable (as much as feasible) competition for off-grid supply services.

As discussed in section 1.1.3, under the arrangements underpinning national energy markets, many aspects of regulation, such as safety and network reliability, are governed primarily by jurisdictional frameworks. Consequently, DNSP-led SAPS can only be effectively regulated if there are complementary changes to both the national and jurisdictional regulatory frameworks.

([19], page 5)

To summarise, the main conclusions from the AEMC's ***Review of the regulatory frameworks for stand-alone power systems*** [19], its accompanied Consultation Paper (**Attachment 1** of [20]) as well as other related studies such as the Consultation Paper "**Roles and Incentives for Microgrids and Stand Alone Power Systems**" [21] prepared by ENERGEIA for the Energy Networks Association (ENA), is that there is an important role of regulatory frameworks in delivering a timely, fair and efficient transition to microgrid technology for both individual customers and communities for the long-term benefit of all consumers. However, to the best of our knowledge, these regulatory frameworks are still being under development/research by different regulatory bodies and they are currently still considering feedback from various stakeholders.

Most importantly, any regulatory framework should specify clearly the obligations of the microgrid operator to ensure the one of the core functions of the microgrid which is to provide backup power during planned outages, unplanned outages, blackouts, and load shedding by the DNSP by safely and seamlessly transitioning from the grid-connected mode to the islanding mode of operation.

7.2 Review of existing regulatory requirements and recommendations in other jurisdictions

As discussed by Marnay et al [24], the regulatory environment into which microgrids are entering is extremely complex, in part because they encroach on multiple areas of existing regulation not conceived with them in mind, i.e., generator interconnection rules, air quality permitting, building codes, tariffication, etc. For instance, traditional interconnection rules required generators to trip in the event of any disturbance, while one of the key objectives of microgrid development is to achieve systems that can island and ride through grid problems, or in some proposals partially so. Clearly, a conflict exists. Subsequently, regulations and policymaking for microgrids have become a great challenge not only in Victoria and Australia but also elsewhere.

According to [23], as of 2019, the US had no national electric microgrid policy but by 2018 a majority of states did with different levels of maturity ranging from with 0 being *no policy*, 1 being *market preparation-only*, 2 being *market creation* (in addition to market preparation if applicable), and 3 being *market expansion* (in addition to market creation and preparation if applicable). For example, for the two neighbouring states: California is at level 3 while Nevada is at level 0. The reason for the lack of an electric microgrid policy at the federal level in the US can be attributed to the following observation made in Marnay et al [24]: "*As with many U.S. regulatory issues, interconnection is seriously complicated because utility regulation resides, in large part, at the state level.*" This is likely to be applicable to Australia and Victoria as well.

Furthermore, Laufer [23] provides some important insights into the evolution of electric microgrid policy in the US over the ten years between 2009 and 2018 using the policy sequencing concept and database created for the analysis. Only Texas and Florida had electric microgrid policies in 2009, but by 2018 a majority of states did, and the evolution can be seen in the following figures reproduced from [23]:

Figure 2. 1: 2009

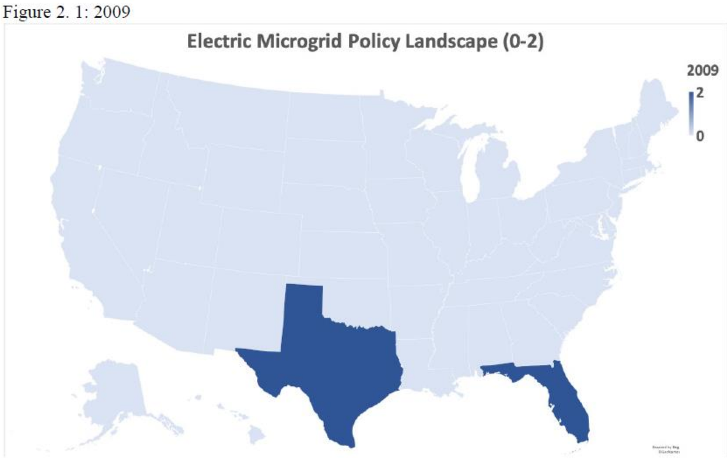


Figure 2. 2: 2014

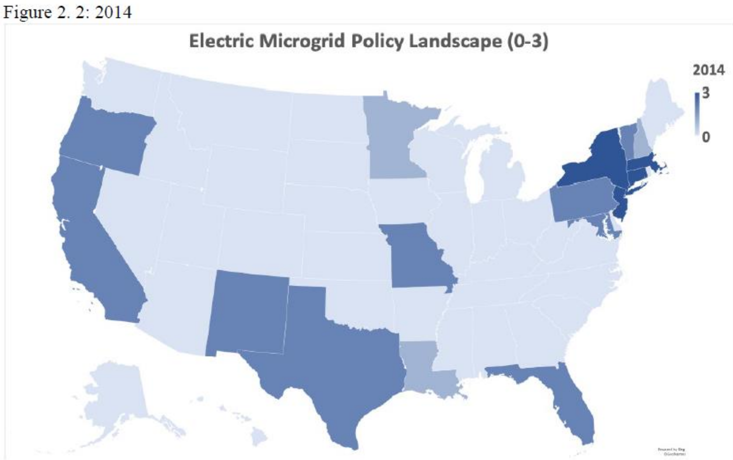


Figure 2. 3: 2018

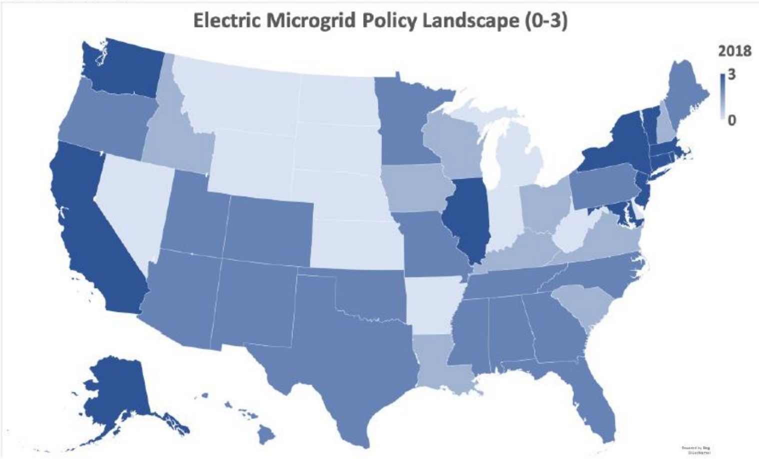


Figure 53: Evolution of electric microgrid policy in the US in ten years (reproduced from [23])

The key takeaway from this review is that, even in the US where microgrid technologies as well as microgrid deployment projects have been developed and rollout much earlier than in Australia, the regulatory environments remain very complex and are still not very matured. In particular, there is not a single regulatory framework applicable across all states of the US. Hence, for microgrids to be successfully developed and deployed in Victoria, the Victoria government must take the initiative to coordinate relevant stakeholders (including DNSPs, retailers, local governments, and communities) to develop a regulatory framework for Victoria. Regarding the *regulatory requirements on de-energisation and re-energisation of microgrids*, the good starting point would be to build on the existing technical standards and requirements for microgrids that have been developed and introduced by various international standardization bodies (including the IEEE and the IEC). These will be reviewed in the following section.

7.3 Existing Technical Standards and Requirements for Microgrids

The interconnection of distributed generation to the conventional network also brings technical challenges such as circuit protection, power quality and reliability and stability issues, which has led to a growing body of research on microgrids . Subsequently, several international standardisation bodies have introduced technical standards and requirements for interconnection of microgrids which have many essential implications on de-energization and re-energization of microgrids.

There are specific technical standards and requirements for the energization, de-energization, and re-energization of microgrids. In particular, re-energization of the microgrids is more critical out of these requirements since isolated grids must meet special criteria because critical customers must be protected and served in such situations. In the following, we provide a summary of the technical requirements according to the **IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces - IEEE SA - IEEE 1547-2018**, the **International Standard IEC 61727** which applies to utility-interconnected photovoltaic (PV) power systems operating in parallel with the utility, and the **Germany Standards for Automatic disconnection device between a generator and the public low-voltage grid - VDE 0126-1-1**. After reviewing the technical requirements, it is clear that, ***depending on the conditions on the distribution feeder and the size of the generators within a microgrid, system impact studies for interconnection may be required. Implementation of a general*** *microgrid would most likely require negotiation of operating agreements between the DNSP and the microgrid owner/operator to delineate bilateral responsibilities that insure system stability. It is worth noting that system impact studies for interconnection are a major undertaking requiring the coordination of the DNSP and the microgrid owner/operator with very detailed technical specifications of the distribution feeder as well as the equipment and devices to be introduced as part of the installation of the microgrid and present one of the biggest costs when deploying a grid-connected microgrid.*

7.3.1 Dispatch function tests

7.3.1.1 Dispatch—steady-state grid-connected scenarios

Table 35: Steady-state, grid-connected scenarios

Initial conditions (see NOTE)	Initiating events	Measurements
1. POI breaker is closed 2. Dispatch orders and objectives 3. Power system state; this includes the breaker statuses, power flow conditions, and unbalance loads 4. Expected minimum, average, and maximum export and import of P and Q 5. Expected minimum, average, and maximum load levels 6. Combinations of dispatchable and non-dispatchable DER	1. Power system disturbances including upstream or microgrid open or short circuit conditions 2. Trip of DERs 3. Setpoint step change 4. Start and stop of largest load 5. Action of all voltage control device	V, f, P, Q, settling time, overshoot, and SS values within contractual requirements and equipment limitations
NOTE—Some initial conditions listed cannot be accomplished with some microgrids. This is because some DER or loads do not have the capacity to be set in the manner requested. If available or possible, all initial condition combinations shown in the table shall be tested		

7.3.3.2 Dispatch—steady-state islanded scenarios

Table 36: Steady-state, islanded scenarios

Initial conditions (see NOTE)	Initiating events	Measurements
1. POI breaker is open 2. Dispatch orders and objectives 3. Power system state; this includes the breaker statuses, power flow conditions, and unbalance loads 4. Expected minimum, average, and maximum load levels	1. Power system disturbances including microgrid open or short circuit conditions 2. Trip of DERs 3. Setpoint step change 4. Start and stop of largest load 5. Action of all voltage control devices 6. Total P and Q load decreased/increased or DER contributions increased/ decreased to the point at which each DER is forced to	V, f, P, Q, settling time, overshoot, and SS values within contractual requirements and equipment limitations

5. Combinations of dispatchable and non-dispatchable DER	anticipated minimum/maximum production levels	

7.3.2 Reconnection mode

To re-energize the distributed energy resources (DERs) and re-connect them to the utility grid from an island mode, monitoring should indicate that the proper conditions exist for synchronizing the islanded microgrid with the electric power system (EPS). A re-energisation is not allowed after an EPS disturbance until the voltage is within Range B of ANSI/NEMA C84.1-2006 as **Figure 54**, the frequency range is between 59.3 Hz to 60.5 Hz, and the phase rotation is correct [Since the Australian power grid operates at 50 Hz, the VDE (Germany standard) values need to be taken into consideration]. Here, it is worth noting that the regulation of voltage and frequency are primary requirements for de-energising and re-energising a part of the system, and the limitations must be met during these processes.

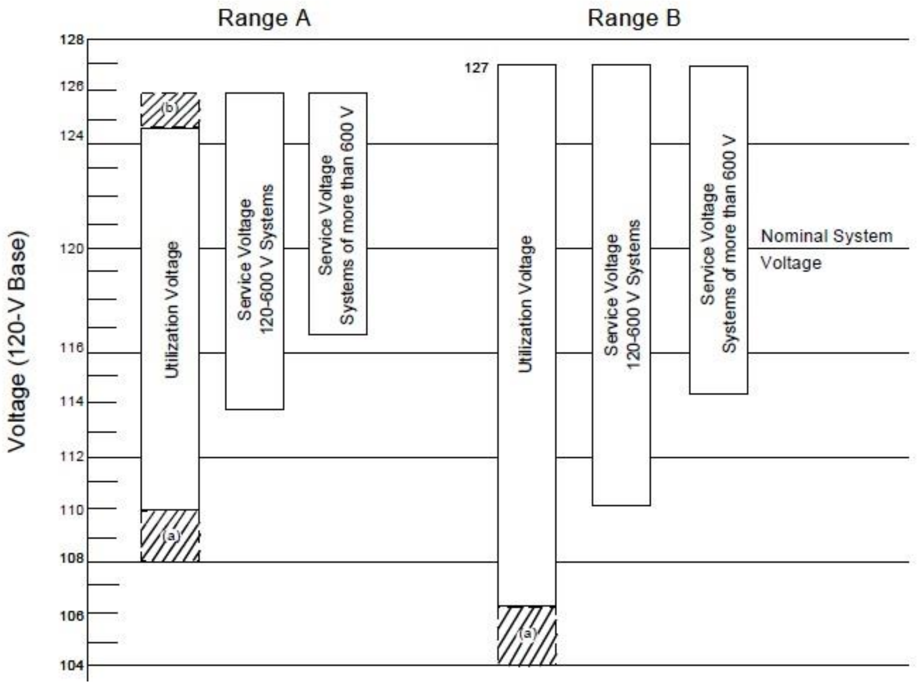


Figure 54: ANSI/NEMA C84.1-2006

Notes:
a. The shaded portions of the ranges do not apply to circuits supplying lighting load
b. The shaded portion of the range does not apply to 120 V - 600 V systems.

From the figure above, the following can be deduced:

For 120 V - 600 V Systems

<u>ANSI C84.1 Service Voltage Limits</u>

- Range A minimum voltage is 95% of nominal voltage
- Range A maximum voltage is 105% of nominal voltage
- Range B minimum voltage is 91.7% of nominal voltage

- Range B maximum voltage is 105.8% of nominal voltage

ANSI C84.1 Utilization Voltage Limits

- Range A minimum voltage is 90% of nominal voltage - refer to Note (a) for limitation
- Range A maximum voltage is 104.2% of nominal voltage - refer to Note (b) for limitation
- Range B minimum voltage is 86.7% of nominal voltage - refer to Note (a) for limitation
- Range B maximum voltage is 105.8% of nominal voltage

For Systems Greater Than 600 V

ANSI C84.1 Service Voltage Limits

- Range A minimum voltage is 97.5% of nominal voltage
- Range A maximum voltage is 105% of nominal voltage
- Range B minimum voltage is 95% of nominal voltage
- Range B maximum voltage is 105.8% of nominal voltage

ANSI C84.1 Utilization Voltage Limits

- Range A minimum voltage is 90% of nominal voltage
- Range A maximum voltage is 105% of nominal voltage
- Range B minimum voltage is 86.7% of nominal voltage
- Range B maximum voltage is 105.8% of nominal voltage

In addition, the difference between minimum service and minimum utilization voltages is intended to allow for voltage drop in the customer's wiring. Moreover, this difference is greater for service at more than 600 volts to allow for additional voltage drop in transformations between service voltage and utilization equipment. The National Electrical Code (NEC) allows up to a 5% drop – up to 3% drop in the main feeder and an additional <3% in individual branch circuits.

Table 37: ANSI C84.1-2006 Service Voltage Range

	For 120-600 V Systems			
Nominal Voltage (V)	**Service Voltage (V)**			
	Range A		**Range B**	
	Max	Min	Max	Min
120	126	114	127	110
240	252	228	254	220
480	504	456	508	440

The voltage, frequency, and phase angle between the two systems should be within acceptable limits (i.e., as specified in **IEEE Std 1547-2003--Table 5**) in order to initiate a reconnection.

Table 38: Synchronization parameter limits for synchronous interconnection to an EPS, or an energized local EPS to an energized Area EPS

Aggregate rating of DR units (kVA)	Frequency difference (∆f, Hz)	Voltage difference (∆V, %)	Phase angle difference (∆Φ, °)
0-500	0.3	10	20
>500-1500	0.2	5	15
_1500-10000	0.1	3	10

The island interconnection device may delay reconnection for up to five minutes after the area electric power system (EPS) steady state voltage and frequency are restored to the ranges identified above. If an unscheduled event triggered the disconnection from the area EPS, the time before reconnection may be extended to ensure the area EPS is stable. If multiple islands exist, a strategy may be adopted to intentionally stagger the return of the islands.

7.3.3 Methods for reconnecting DER-integrated islanding systems back to the EPS

There are several ways to reconnect the DER-integrated islanding systems back to the EPS:

- In active synchronization, there is a control mechanism that can be used to match the voltage, frequency, and phase angle of the distributed energy resources (DER) island system to the area EPS before initiating a reconnection. This technique requires sensing of the area EPS and DER island system conditions and that this information is communicated to the control mechanism.
- Passive synchronization employs a synchronization check for the DER island system paralleling device, which only reconnects the systems within acceptable limits. This device will only reconnect if the synchronization requirements for voltage, frequency, and phase angle are within a certain range to ensure minimal disturbance. This technique also requires sensing of the area EPS and DER island systems conditions and may take longer to reconnect than the active synchronization.
- Open-transition transfer of the DR island system to the area EPS would entail an interruption of the loads served within the DER island system. In this reconnection strategy, the load and DR are deenergized before reconnection to the EPS. DER island system synchronization sensors are not required for this reconnection.

Once the DER island system is paralleled to the area EPS, all DER shall return to IEEE 1547 compliance within area EPS time requirements.

7.3.4 Technical requirements for de-energisation:

Table 39: Public distribution grid voltage harmonics limits – EN 50160

Odd harmonics				Even harmonics	
No multiple of 3		Multiple of 3			
Order h	Relative voltage (%)	Order h	Relative Voltage (%)	Order h	Relative voltage (%)
5	6	3	5	2	2
7	5	9	1.5	4	1

11	3.5	15	0.5	6 to 24	0.5
13	3	21	0.5		
17	2				
19	1.5				
23	1.5				
25	1.5				

Table 40: Disconnection time for voltage variations

IEEE 1547		IEC 61727		VDE 0126-1-1	
Voltage range (%)	Disconnection time (sec)	Voltage range (%)	Disconnection time (sec)	Voltage range (%)	Disconnection time (sec)
$V < 50$	0.16	$V < 50$	0.1	$110 \leq V < 85$	0.2
$50 \leq V \leq 88$	2	$50 \leq V \leq 85$	2		
$110 \leq V < 120$	1	$110 \leq V < 135$	2		
$V \geq 120$	0.16	$V \geq 135$	0.05		

Table 41: Disconnection time for frequency variations

IEEE 1547		IEC 61727		VDE 0126-1-1	
Frequency range (Hz)	Disconnection time (sec)	Frequency range (Hz)	Disconnection time (sec)	Frequency range (Hz)	Disconnection time (sec)
$59.3 < f < 60.5$	0.16	$f_n - 1 < f < f_n + 1$	0.2	$47.5 < f < 50.2$	0.2

Table 42: Conditions for reconnection after trip

IEEE 1547	IEC 61727	VDE 0126-1-1
$88 < V < 110$ (%) AND $59.3 < f < 60.5\ (Hz)$	$85 < V < 110$ (%) AND $f_n - 1 < f < f_n + 1\ (Hz)$ AND Minimum delay of 3 min	

Table 43: DC current injection limitation

IEEE 1547	IEC 61727	VDE 0126-1-1
$I_{DC} < 0.5$ (%)	$I_{DC} < 1$ (%)	$I_{DC} < a1\ A$

of the rated RMS current	of the rated RMS current	Maximum trip time 0.2 sec

7.4 Other Standards or Policies on Interconnection

Despite our best effort to review existing standards and policies on interconnection of microgrids and/or distributed energy resources (DER) to a main utility grid, this review is by no mean exhaustive. A more thorough review should also cover the following:

1. **EU Standards**: **EN 50549 (2019)** Requirements for generating plants to be connected in parallel with distribution networks (including *Part 1: Connection to a LV distribution network - Generating plants up to and including Type B* and *Part 2: Connection to a MV distribution network - Generating plants up to and including Type B*) – see [27]
2. **Canada**: **CSA C22.3 No. 9-2020** Interconnection Of Distributed Energy Resources And Electricity Supply Systems – see [28]

3. **IEC**: **IEC TS 62898** – Microgrids (including *Part 1: Guidelines for microgrid projects planning and specification; Part 2: Guidelines for operation* and *Part 3-1: Technical requirements - Protection and dynamic control*) – see [29]

4. **The UK**: **Engineering Recommendations G59 and G83**: Recommendations for the Connection of. Generating Plant to the Distribution Systems – see [30]

5. **California, USA**:
    a. **Rule 21 – Interconnection** [31]
    b. **California Interconnection Guidebook** [32]

7.5 Recommended regulatory changes

An uncertain regulatory environment poses an unnecessary barrier to the development and adoption of microgrid systems. Regulators and policymakers should create new laws and policies as well as make changes to existing ones so that microgrid systems can participate and compete in a new market for energy and energy services. These changes need to be effective, while still limiting system risk and protecting the rights of both the microgrid and the utility customers. Based on the analyses outlined in the preceding sections, we are making the following recommendations regarding potential regulatory requirements related to de-energisation and re-energisation of microgrids:

1. **Formalize the definition and ownership models of microgrids:** It is important for regulators and policymakers to refer to microgrids under a common definition across all levels of government and regulatory bodies. More specifically, we strongly recommend that the following definition of a microgrid, provided by the U.S. Department of Energy (DOE), be adopted:

> *"A microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode. A remote microgrid is a variation of a microgrid that operates in islanded conditions."*

U.S. Department of Energy Electricity Grid Research and Development [25]

The above definition is consistent with the definition found on the website of the Department of Environment, Land, Water and Planning (DELWP) of the Victoria State Government [18]. It is also consistent with the microgrid definition is given by The International Council on Large Electrical Systems (CIGRE) [26]: "*Microgrids are electricity distribution systems containing loads and distributed energy resources (such as distributed generators, storage devices, or controllable loads,) that can be operated in a controlled, coordinated way either while connected to the main power network or while islanded.*"

Also, different ownership models of microgrids need to be clearly defined with customised licensing and interconnection procedures for each model specified and regulated.

2. **Introduce/Adopt standardised interconnection/ de-energisation/ re-energisation procedures that are applicable to microgrids:** Regulators and policymakers should consult well-established international technical standards and requirements (such as the **IEEE 1547**, the **FERC**'s ***Standardization of Small Generator Interconnection Agreements and Procedures***, the **IEC 61727**) as well as model interconnection procedures (such as the one developed by the **National Association of Regulatory Utility Commissioners** (**NARUC**) which has been implemented in many states in the US) and introduce/adopt standardized interconnection procedures for micrograms. Timelines, procedural steps, and the responsibilities of all involved parties (e.g., the microgrid owner, the microgrid operator and the DNSP/retailer) should be clearly laid out. These required procedures can have critical impacts on the microgrids customers as well as other stakeholders such as the DNSP in terms of safe operation of the grid/microgrids and the power quality and reliability.

3. **Limit system and network risk (coupled with a clear interpretation and implication for end users):** Regulators should adopt standardized minimum technical interconnection requirements that are applicable to microgrids. Technical requirements – and associated equipment requirements – should not be subject to much interpretation or expansion by the DNSP/retailer without approval from regulators. Furthermore, there should be a simple interpretation of these requirements to the end users/customers to allow them to understand how such requirements may affect their households and/or businesses. Again, these technical and equipment requirements can have critical impacts on the stakeholders of microgrids in terms of safety, power quality and reliability and costs.

4. **Consistency with relevant regulations and policies:** If Recommendation 1 above will be adopted then it is clear that Embedded Networks become a variation of microgrids (without the ability to operate in island mode). Thus, it is important that there be consistency across the regulations and policies for embedded networks and microgrids where applicable. As the regulatory frameworks for embedded networks can be considered better established, they can be considered for microgrids while connected to the main power network. Moreover, we recommend aggregating these related systems into a common framework

for microgrids with both the embedded networks and the remote microgrids that operate permanently in island mode (i.e., SAPS) being different variations of microgrids.

7.6 Conclusions

We conducted a comprehensive review into the regulatory frameworks for microgrids in Australia, in Victoria and also in other jurisdictions. We observe that currently in Australia there are different definitions of microgrids, and this has caused significant problems for regulators and policymakers and relevant stakeholders. We subsequently conducted a review into different definitions used by various regulatory bodies in Australia and Victoria. Thus, we carried out a comprehensive review into relevant regulatory frameworks in Australia (including those for *embedded networks* and *standalone power systems*) and identified a number of critical issues around customer protection.

In order to identify regulatory requirements for de-energisation and re-energisation of microgrids, we have reviewed the technical requirements introduced by various international standardisation bodies (including the **IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces - IEEE SA - IEEE 1547-2018**, the **International Standard IEC 61727** which applies to utility-interconnected photovoltaic (PV) power systems operating in parallel with the utility, and the **Germany Standards for Automatic disconnection device between a generator and the public low-voltage grid** - **VDE 0126-1-1**). Observe that there are several other relevant standards and policies on interconnection that may also be considered (see Section 7.4).

Finally, based on our reviews into the state of the regulatory frameworks in Australia and Victoria as well as the international technical standards and requirements for microgrids, we provided four (4) recommendations for regulatory bodies in Australia and Victoria regarding the introduction and adoption of regulatory requirements for de-energisation and re-energisation of microgrids.

8. Concluding remarks

The modern microgrid concept has gained increasing interest as a promising solution for energy systems that can deliver many benefits such as energy security, cost savings and sustainability. These are especially important in the context of regional Victorian towns (such as Donald and Tarnagulla) with supply vulnerabilities due to natural disasters (e.g., bushfires) and unreliable transmission/distribution networks. Nevertheless, a careful stakeholder impact investigation is important to understand the costs and benefits implications a microgrid of certain design and size can have on relevant stakeholders. A science-based analysis of such implications would not be possible without a detailed appliance model of the loads to be connected to the microgrid and, more importantly, the customer's preference profiles as well as details of a cost model for different technologies to be installed with the microgrids (including a microgrid control system with the capability of seamless transition between grid-connected and islanded modes of operation and distributed energy resources such as generators and battery energy storage systems). In the absence of these important inputs, we have made a number of assumptions to allow us to carry out comprehensive what-if analyses for different hypothetical scenarios that can best simulate the available smart meter data as well as the available information about the customers in the two towns of Donald and Tarnagulla. Based on our analyses, the following conclusions can be drawn:

1. By taking into consideration the criteria of power supply security, costs and sustainability with supply security and power quality and reliability taking priority over the other criteria, the best

integration of technologies is PVs, batteries and diesel gensets. A fully sustainable option of integrating PVs and batteries only would not be economically viable if supply security needs to be guaranteed.

2. While the cost of energy (COE) can be quite high when the microgrid needs to operate in the islanding mode for extended durations (e.g., during periods of natural disasters), the integration of PV panels and batteries ensures that the community can benefit from significant cost savings. A detailed analysis into potential cost savings requires data about the arrangement the microgrid would have with the DNSP and the retailers and the arrangement between the microgrid owner/operator with the customers of the microgrid. However, the claimed benefits are on the basis of the cost savings the community would receive by consuming the energy generated by the PV panels and stored in the batteries rather than having to purchase from the main grid. These cost savings may or may not consider the potential energy export to the main grid from the microgrid.
3. An appropriately designed and sized microgrid equipped with advanced microgrid control systems (MGCS) technology and provided that the diesel gensets have sufficient fuel supply, the designated loads (e.g., the community-critical loads only or both the community-critical loads and the medium-flexible loads) of the microgrid are guaranteed to be supplied. Hence, supply security for the community can be guaranteed.
4. The flexibility a customer has regarding the supply security can vary across different loads in their household or at their business. That is, not all loads at a customer's household or business are equal. Hence, some loads can be shedded and some loads can be shifted to a different time for the purpose of flattening the overall peak load leading to better power quality and cost saving. A detailed investigation into this issue requires detailed appliance modelling and customers' preference profiles which were not available. Nevertheless, a software tool has been developed to enable this study when data are available.
5. Regulations present the greatest barrier to the development and adoption of microgrids. There remain many regulatory uncertainties regarding microgrids in Australia and Victoria. An AEMC's review of regulatory frameworks for microgrids leave the most challenging areas of microgrid regulation with states and territories. The Victorian government can consult the regulatory frameworks in a number of states in the US with high level of regulatory framework maturity (**Level 3**) such as California, New York and Washington (see **Figure 53**).
6. Regarding the regulatory requirements for de-energisation and re-energisation of microgrids, regulators and policymakers should consult model interconnection procedures (such as the one developed by the **National Association of Regulatory Utility Commissioners** (**NARUC**) which has been implemented in many states in the US). Regulators and policymakers should adopt standardized minimum technical interconnection requirements that are applicable to microgrids (e.g., **IEEE 1547**, the **FERC**'s ***Standardization of Small Generator Interconnection Agreements and Procedures***, the **IEC 61727**).
7. Technical requirements – and associated equipment requirements – should not be subject to much interpretation or expansion by the DNSP/retailer without approval from regulators. Furthermore, there should be a simple interpretation of these requirements to the end users/customers to allow them to understand how such requirements may affect their households and/or businesses. Again, these technical and equipment requirements can have critical impacts on the stakeholders of microgrids in terms of safety, power quality and reliability and costs.
8. A full list of recommended regulatory changes can be found in **Section 7.5** of this report.

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Appendices

Appendix A

The results of techno-economic analysis for Donald network under different scenarios

Table 44: A summary of the designed system for Donald area in HOMER Pro

<table>
<tr><th rowspan="2">Criteria and Aim</th><th rowspan="2">SDG7 Criteria</th><th rowspan="2">Indicator with Units</th><th colspan="2">Configurations</th></tr>
<tr><th>PV + DG + Battery</th><th>PV + Battery</th></tr>
<tr><td rowspan="6">Capacities</td><td>Generation</td><td>P (kW)</td><td>PV: 3,595
DG: 800, 320, 1200, 400
Batt: 840
Conv: 607</td><td>PV: 54,215
Batt: 53,895
Conv: 4,504</td></tr>
<tr><td rowspan="5">Consumption</td><td>Average (kWh/day)</td><td colspan="2">25,467</td></tr>
<tr><td>Average (kW)</td><td colspan="2">1,061</td></tr>
<tr><td>Peak (kW)</td><td colspan="2">2,355</td></tr>
<tr><td>Load Factor</td><td colspan="2">0.39</td></tr>
<tr><td>Peak Month</td><td colspan="2">July</td></tr>
<tr><td rowspan="14">Criteria</td><td rowspan="3">Affordable</td><td>Lower NPC ($)</td><td>47.4M</td><td>157M</td></tr>
<tr><td>Lower COE ($/kWh)</td><td>0.323</td><td>1.07</td></tr>
<tr><td>Lower initial capital cost</td><td>6.61M</td><td>114M</td></tr>
<tr><td rowspan="4">Reliable</td><td>Continuous power supply (when renewables and ES fail)</td><td>DGs meet the criteria</td><td>Cannot meet</td></tr>
<tr><td>Excess electricity or buffer for future (kWh/y)</td><td>2,460,042</td><td>65,385,025</td></tr>
<tr><td>Minimize the capacity of shortage (kWh/y)</td><td>0</td><td>9.281</td></tr>
<tr><td>Quality of power</td><td colspan="2">Needs more evaluation through DIgSILENT analysis</td></tr>
<tr><td rowspan="3">Sustainable</td><td>Lower emissions per year (kg/y)</td><td>4,684,081</td><td>0</td></tr>
<tr><td>Lower emissions per service (kg/service life)</td><td>31,797</td><td>0</td></tr>
<tr><td>Higher renewable energy fraction (%)</td><td>27.2</td><td>100</td></tr>
<tr><td rowspan="3">Modern</td><td>MGs</td><td>✓</td><td>✓</td></tr>
<tr><td>Hybrid power systems</td><td>✓</td><td>✓</td></tr>
<tr><td>Community MGs</td><td>✓</td><td>×</td></tr>
<tr><td>Aim</td><td>Energy access</td><td>Unmet electricity (kWh/y)</td><td>0</td><td>7,997</td></tr>
</table>

Table 45: Donald network: Scenario A with categories 0 and 1

Criteria and Aim	SDG7 Criteria	Indicator with Units	Configurations	
			PV + DG + Battery	PV + Battery
Capacities	Generation	P (kW)	PV: 3,176 DG: 800, 320, 1200, 400 Batt: 818 Conv: 593	PV: 39,650 Batt: 45,724 Conv: 4,980
	Consumption	Average (kWh/day)	21,062	
		Average (kW)	877.59	
		Peak (kW)	2,301	
		Load Factor	0.43	
		Peak Month	July	
Criteria	Affordable	Lower NPC ($)	38.2M	125M
		Lower COE ($/kWh)	0.316	1.04
		Lower initial capital cost	6.08M	89.2M
	Reliable	Continuous power supply (when renewables and ES fail)	DGs meet the criteria	Cannot meet
		Excess electricity or buffer for future (kWh/y)	2,018,629	46,834,747
		Minimize the capacity of shortage (kWh/y)	0	7,279
		Quality of power	Needs more evaluation through DIgSILENT analysis	
	Sustainable	Lower emissions per year (kg/y)	3,677,128	0
		Lower emissions per service (kg/service life)	24,526	0
		Higher renewable energy fraction (%)	31	100
	Modern	MGs	✓	✓
		Hybrid power systems	✓	✓
		Community MGs	✓	×
Aim	Energy access	Unmet electricity (kWh/y)	0	6,535

Table 46: Donald network: Scenario A with category 0 only

Criteria and Aim	SDG7 Criteria	Indicator with Units	Configurations	
			PV + DG + Battery	PV + Battery
Capacities	Generation	P (kW)	PV: 608 DG: 320, 400 Batt: 263 Conv: 182	PV: 5,419 Batt: 6,050 Conv: 546
	Consumption	Average (kWh/day)	2,953	
		Average (kW)	123	
		Peak (kW)	329	
		Load Factor	0.37	
		Peak Month	July	
Criteria	Affordable	Lower NPC ($)	5.84M	16.7M
		Lower COE ($/kWh)	0.344	0.986
		Lower initial capital cost	1.17M	12M
	Reliable	Continuous power supply (when renewables and ES fail)	DGs meet the criteria	Cannot meet
		Excess electricity or buffer for future (kWh/y)	403,490	6,392,715
		Minimize the capacity of shortage (kWh/y)	0	1,058
		Quality of power	Needs more evaluation through DIgSILENT analysis	
	Sustainable	Lower emissions per year (kg/y)	499,399	0
		Lower emissions per service (kg/service life)	2,736	0
		Higher renewable energy fraction (%)	40.1	100
	Modern	MGs	✓	✓
		Hybrid power systems	✓	✓
		Community MGs	✓	×
Aim	Energy access	Unmet electricity (kWh/y)	0	940

Table 47: Donald network: Scenario B with categories 0 and 1

Criteria and Aim	SDG7 Criteria	Indicator with Units	Configurations	
			PV + DG + Battery	PV + Battery
Capacities	Generation	P (kW)	PV: 4,105 DG: 800, 1200, 320, 1200 Batt: 1,038 Conv: 742	PV: 46.359 Batt: 50,949 Conv: 4,283
	Consumption	Average (kWh/day)	24,810	
		Average (kW)	1,033	
		Peak (kW)	2,183	
		Load Factor	0.47	
		Peak Month	July	
Criteria	Affordable	Lower NPC ($)	43.6M	142M
		Lower COE ($/kWh)	0.306	0.993
		Lower initial capital cost	7.46M	101M
	Reliable	Continuous power supply (when renewables and ES fail)	DGs meet the criteria	Cannot meet
		Excess electricity or buffer for future (kWh/y)	2,546,670	54,763,819
		Minimize the capacity of shortage (kWh/y)	0	8,903
		Quality of power	Needs more evaluation through DIgSILENT analysis	
	Sustainable	Lower emissions per year (kg/y)	4,100,444	0
		Lower emissions per service (kg/service life)	27,553	0
		Higher renewable energy fraction (%)	34.7	100
	Modern	MGs	✓	✓
		Hybrid power systems	✓	✓
		Community MGs	✓	×
Aim	Energy access	Unmet electricity (kWh/y)	0	7,985

Table 48: Donald network: Scenario B with category 0 only

Criteria and Aim	SDG7 Criteria	Indicator with Units	Configurations	
			PV + DG + Battery	PV + Battery
Capacities	Generation	P (kW)	PV: 732 DG: 320 Batt: 287 Conv: 204	PV: 7,196 Batt: 7,199 Conv: 883
	Consumption	Average (kWh/day)	3,764	
		Average (kW)	156.8	
		Peak (kW)	395.1	
		Load Factor	0.4	
		Peak Month	July	
Criteria	Affordable	Lower NPC ($)	7.11M	21.1M
		Lower COE ($/kWh)	0.328	0.977
		Lower initial capital cost	1.35M	15.3M
	Reliable	Continuous power supply (when renewables and ES fail)	DGs meet the criteria	Cannot meet
		Excess electricity or buffer for future (kWh/y)	474,324	8,549,185
		Minimize the capacity of shortage (kWh/y)	722	1,374
		Quality of power	Needs more evaluation through DIgSILENT analysis	
	Sustainable	Lower emissions per year (kg/y)	624,275	0
		Lower emissions per service (kg/service life)	3,420	0
		Higher renewable energy fraction (%)	38.9	100
	Modern	MGs	✓	✓
		Hybrid power systems	✓	✓
		Community MGs	✓	×
Aim	Energy access	Unmet electricity (kWh/y)	19.2	1,234

Appendix B

The results of techno-economic analysis for Tarnagulla network under different scenarios

Table 49: A summary of the designed system for Tarnagulla area in HOMER Pro

Criteria and Aim	SDG7 Criteria	Indicator with Units	Configurations	
			PV + DG + Battery	PV + Battery
Capacities	Generation	P (kW)	PV: 417 DG: 320 Batt: 567 Conv: 135	PV: 3,127 Batt: 5,494 Conv: 452
	Consumption	Average (kWh/day)	2569	
		Average (kW)	107	
		Peak (kW)	215.7	
		Load Factor	0.5	
		Peak Month	July	
Criteria	Affordable	Lower NPC ($)	4.31M	12.7M
		Lower COE ($/kWh)	0.381	1.12
		Lower initial capital cost	1.17M	8.67M
	Reliable	Continuous power supply (when renewables and ES fail)	DGs meet the criteria	Cannot meet
		Excess electricity or buffer for future (kWh/y)	203,911	3,574,655
		Minimize the capacity of shortage (kWh/y)	0	708
		Quality of power	Needs more evaluation through DIgSILENT analysis	
	Sustainable	Lower emissions per year (kg/y)	295,692	0
		Lower emissions per service (kg/service life)	1,620	0
		Higher renewable energy fraction (%)	48.5	0
	Modern	MGs	✓	✓
		Hybrid power systems	✓	✓
		Community MGs	✓	×
Aim	Energy access	Unmet electricity (kWh/y)	0	634

Table 50: Tarnagulla network: Scenario A with categories 0 and 1

Criteria and Aim	SDG7 Criteria	Indicator with Units	Configurations	
			PV + DG + Battery	PV + Battery

Capacities	Generation	P (kW)	PV: 417 DG: 320 Batt: 567 Conv: 135	PV: 3,127 Batt: 5,494 Conv: 452
	Consumption	Average (kWh/day)	1967	
		Average (kW)	82	
		Peak (kW)	198.3	
		Load Factor	0.41	
		Peak Month	July	
Criteria	Affordable	Lower NPC ($)	4.31M	12.7M
		Lower COE ($/kWh)	0.381	1.12
		Lower initial capital cost	1.17M	8.67M
	Reliable	Continuous power supply (when renewables and ES fail)	DGs meet the criteria	Cannot meet
		Excess electricity or buffer for future (kWh/y)	203,911	3,574,655
		Minimize the capacity of shortage (kWh/y)	0	708
		Quality of power	Needs more evaluation through DIgSILENT analysis	
	Sustainable	Lower emissions per year (kg/y)	295,692	0
		Lower emissions per service (kg/service life)	1,620	0
		Higher renewable energy fraction (%)	48.5	0
	Modern	MGs	✓	✓
		Hybrid power systems	✓	✓
		Community MGs	✓	×
Aim	Energy access	Unmet electricity (kWh/y)	0	634

Table 51: Tarnagulla network: Scenario A with category 0 only

Criteria and Aim	SDG7 Criteria	Indicator with Units	Configurations	
			PV + DG + Battery	PV + Battery

Capacities	Generation	P (kW)	PV: 34.4 DG: 320 Batt: 97 Conv: 51.6	PV: 141 Batt: 214 Conv: 51.6
	Consumption	Average (kWh/day)	82.21	
		Average (kW)	3.43	
		Peak (kW)	22	
		Load Factor	0.16	
		Peak Month	June	
Criteria	Affordable	Lower NPC ($)	385,966	0.385,966
		Lower COE ($/kWh)	0.817	1.14
		Lower initial capital cost	270,631	369,758
	Reliable	Continuous power supply (when renewables and ES fail)	DGs meet the criteria	Cannot meet
		Excess electricity or buffer for future (kWh/y)	25,917	169,650
		Minimize the capacity of shortage (kWh/y)	0	27.5
		Quality of power	Needs more evaluation through DIgSILENT analysis	
	Sustainable	Lower emissions per year (kg/y)	8,544	0
		Lower emissions per service (kg/service life)	46.8	0
		Higher renewable energy fraction (%)	65.6	100
	Modern	MGs	✓	✓
		Hybrid power systems	✓	✓
		Community MGs	✓	×
Aim	Energy access	Unmet electricity (kWh/y)	0	22.4

Table 52: Tarnagulla network: Scenario B with categories 0 and 1

Criteria and Aim	SDG7 Criteria	Indicator with Units	Configurations	
			PV + DG + Battery	PV + Battery
Capacities	Generation	P (kW)	PV: 345 DG: 320 Batt: 184 Conv: 115	PV: 3,783 Batt: 4,242 Conv: 464

	Consumption	Average (kWh/day)	2,145	
		Average (kW)	90	
		Peak (kW)	208	
		Load Factor	0.43	
		Peak Month	July	
Criteria	Affordable	Lower NPC ($)	4.66M	11.8M
		Lower COE ($/kWh)	0.378	0.956
		Lower initial capital cost	750,817	8.41M
	Reliable	Continuous power supply (when renewables and ES fail)	DGs meet the criteria	Cannot meet
		Excess electricity or buffer for future (kWh/y)	234,883	4,560,822
		Minimize the capacity of shortage (kWh/y)	0	781
		Quality of power	Needs more evaluation through DIgSILENT analysis	
	Sustainable	Lower emissions per year (kg/y)	421,856	0
		Lower emissions per service (kg/service life)	2,311	0
		Higher renewable energy fraction (%)	31.8	100
	Modern	MGs	✓	✓
		Hybrid power systems	✓	✓
		Community MGs	✓	×
Aim	Energy access	Unmet electricity (kWh/y)	0	705

Table 53: Tarnagulla network: Scenario B with category 0 only

Criteria and Aim	**SDG7 Criteria**	**Indicator with Units**	**Configurations**	
			PV + DG + Battery	**PV + Battery**
Capacities	Generation	P (kW)	PV: 34.4 DG: 320 Batt: 97 Conv: 51.6	PV: 141 Batt: 214 Conv: 31.7
	Consumption	Average (kWh/day)	154,9	

		Average (kW)	6.46	
		Peak (kW)	22.2	
		Load Factor	0.29	
		Peak Month	August	
Criteria	Affordable	Lower NPC ($)	385,966	536,663
		Lower COE ($/kWh)	0.817	1.14
		Lower initial capital cost	270,631	369,758
	Reliable	Continuous power supply (when renewables and ES fail)	DGs meet the criteria	Cannot meet
		Excess electricity or buffer for future (kWh/y)	25,917	169,650
		Minimize the capacity of shortage (kWh/y)	0	27.5
		Quality of power	Needs more evaluation through DIgSILENT analysis	
	Sustainable	Lower emissions per year (kg/y)	8,544	0
		Lower emissions per service (kg/service life)	46.8	0
		Higher renewable energy fraction (%)	65.6	100
	Modern	MGs	✓	✓
		Hybrid power systems	✓	✓
		Community MGs	✓	×
Aim	Energy access	Unmet electricity (kWh/y)	0	22.4

Appendix C

This appendix provides the formulation of reliability assessment in terms of security criteria:

- **Reliability indices at load point i:**

The load point interruption frequency in a year for load point i is defined by the following expression:

$$LPIF_i = \sum_k Fr_k \qquad \text{(Unit: 1/a)} \qquad (1)$$

Where Fr_k is the frequency of occurrence of contingency k for which it is a random variable indicating the number of failures in a year of the probable element k [6]. Now, if the probability of occurrence of contingency k be Pr_k, the interruption time of the load point i in one year as hourly based (i.e. $365\ days \times 24\ h = 8760\ h$) is expressed by the following equation:

$$LPIT_i = \sum_k 8760. Pr_k \qquad \text{(Unit: h/a)} \qquad (2)$$

In order to find the failure rate frequency of each probable component at load point i, if $frac_{i,k}$ is defined as the fraction of the load which is lost at load point i, for contingency k, then, the average customer interruption frequency at load point i (i.e. the failure rate frequency (λ_i)) is determined as follows:

$$\lambda_i = ACIF_i = \sum_k Fr_k . frac_{i,k} \qquad \text{(Unit: 1/a)} \qquad (3)$$

By following the similar analysis for $LPIT_i$, the average customer interruption time is calculated by the following expression:

$$ACIT_i = \sum_k 8760. Pr_k . frac_{i,k} \qquad \text{(Unit: h/a)} \qquad (4)$$

Now, by considering N_i as the number of customers supplied by load point i and equation (3), the total customer interruption frequency at load point I is determined

$$TCIF_i = ACIF_i . N_i \qquad \text{(Unit: C/a)} \qquad (5)$$

Furthermore, the interruption time for the total customers at load point i can be found by considering N_i and equation (4) as follows:

$$TCIT_i = ACIT_i . N_i \qquad \text{(Unit: Ch/a)} \qquad (6)$$

The energy not supplied at load point i is one of the most important factors for the evaluation of the system at each load point, in which is determined by using the following expression:

$$LPENS_i = ACIT_i . (Pd_i + Ps_i) \qquad \text{(Unit: MWh/a)} \qquad (7)$$

Where Pd_i and Ps_i are the weighted average amount of power disconnected and the weighted average amount of power shed at load point i, respectively.

- **Reliability indices for the entire system:**

By considering the failure rate of each equipment at load point i, (i.e. equation (3)), the system average interruption frequency is calculated by the following term:

$$SAIFI = \frac{\text{Total number of customer interruptions}}{\text{Total number of customer supplied}} = \frac{\sum \lambda_i . N_i}{\sum N_i} \qquad \text{(Unit: 1/C/a)} \qquad (8)$$

Furthermore, if A_i is defined as the number of affected customers for an interruption at load point i, then the customer average interruption frequency index can be determined as follows:

$$CAIFI = \frac{\text{Total number of customer interruptions}}{\text{Total number of customer affected}} = \frac{\sum \lambda_i . N_i}{\sum A_i} \qquad \text{(Unit: 1/A/a)} \qquad (9)$$

By following the similar manner and considering the equation (4), the system average interruption duration index is also found by:

$$SAIDI = \frac{\text{Total customer interruption durations}}{\text{Total number of customer supplied}} = \frac{\sum ACIT_i . N_i}{\sum N_i} \qquad \text{(Unit: h/C/a)} \qquad (10)$$

Finally, the customer average interruption duration index (CAIDI) is defined by utilizing the proportion of SAIDI and SAIFI as follows:

$$CAIDI = \frac{SAIDI}{SAIFI} \qquad \text{(Unit: h)} \qquad (11)$$

On the other hand, the total energy not supplied can be calculated by aggregating the energy not supplied of all load points by using equation (7) for which we have:

$$ENS = \sum LPENS_i \qquad \text{(Unit: MWh/a)} \qquad (12)$$

Therefore, the average energy not supplied can easily be calculated by considering all customers as follows:

$$AENS = \frac{ENS}{\sum N_i} \quad \text{(Unit: 1/a)} \qquad (13)$$

In addition, by considering L_m as the total connected kVA interrupted of each interruption event m and L_T as the total connected kVA supplied, the average system interruption frequency index is computes by the following expression:

$$ASIFI = \frac{\sum L_m}{L_T} \quad \text{(Unit: 1/a)} \qquad (14)$$

Finally, the average system interruption duration index is calculated by the following term:

$$ASIDI = \frac{\sum(r_m \times L_m)}{L_T} \quad \text{(Unit: h/a)} \qquad (15)$$

where, r_m is defined as the duration of each interruption event m.

Appendix D

This appendix provides the formulation of reliability assessment in terms of generation adequacy criteria:

- **Loss of Load Probability**

In order to find the loss of load probability (LOLP), the analysis can be started from the following simple equation, which basically defines the balance between generation and consumption:

$$DNS = \sum Demand - \sum Generation \qquad (16)$$

In the first view, the expression for DNS seems to be very simple equation; however, it is not too simple in real power networks as both demand and generation consist of different uncertainties. By utilizing the equation (16), the LOLP can be determined as follows:

$$LOLP\ (\%) = \frac{N_{DNS}}{N} \times 100 \qquad (17)$$

where N_{DNS} is the number of iterations and N is the total number of iterations.

- **Expected Demand Not Supplied**

The expected demand not supplied is the other important index in generation adequacy evaluation, which is defined by the following expression:

$$EDNS = \frac{\sum DNS}{N} \quad \text{Unit (kW)} \qquad (18)$$