Donald and Tarnagulla Microgrid Study: Recommendations to regulators on microgrids

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FINAL REPORT

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Authorship

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Recommendations to regulators on microgrids

Final report

This is the final report of *Project 11: Recommendations to Regulators*, a study being undertaken independently by the University of Melbourne as part of the Donald and Tarnagulla Microgrid Feasibility Study.

The Donald and Tarnagulla Microgrid Feasibility Study is a three-year project supported by the Department of Industry, Science, Energy and Resources and coordinated by the Centre for New Energy Technologies (C4NET) that seeks to understand the feasibility of microgrids while considering the technical, cultural and social contexts. The project comprises 12 components covering key aspects of the feasibility of establishing microgrids in Donald and Tarnagulla:

2. **Community Engagement:**[1] A mix of surveys, interviews, community meetings and information updates for energy consumers impacted to determine energy needs, appeal of various trade-offs, what changes to current supply could be accepted and behavioural change elements. Undertaken by Swinburne University and the Central Victorian Greenhouse Alliance (CVGA).
3. **Network Assessment:** to assess the current and forecast status of supply to Donald and Tarnagulla, include grid and customer characteristics, demand peak, volume, events impact, known constraints, and power quality analysis. Undertaken by Powercor.
4. **Area Hosting Capacity Assessment:** To model, for each town, different hosting scenarios for self-generation including solar, diesel/gas gen-sets, storage and demand response options, while accounting for network constraints. Undertaken by RMIT University.
5. **Islanding Design and Cost Analysis:** Identifying the optimal location for islanding point, design elements, the cost of doing so (hardware, installation and ongoing operational), and network connection assessment. Undertaken by Federation University and RMIT University.
6. **Stakeholder Impact Investigation:** Undertaking customer critical needs analysis and determining the microgrid's ability to prioritise supply ranking if islanding occurs (eg hospital, life support premises, commercial/residential considerations), impact on business attractiveness, and regulatory requirements for de-energising and re-energising. Undertaken by Swinburne University.
7. **Microgrid Impact Study:** modelling the microgrid impact (full-time, partial, and status quo), covering both the islanding component and its impact on the broader network. Will consider event-driven microgrid appeal such as high bushfire danger days and how many critical event days are likely to occur, cost of covering them, and so on. Undertaken by the University of Melbourne.

[1] The projects are numbered from #2 because the project launch event was project #1

8. **Economic And Risk Assessment:** Analysing the value potential created, investment required, alternatives (including network storage etc) and community effects (impact on all grid-users) and risks. Undertaken by the University of Melbourne.
9. **Concentrated Generation Impact (Demonstration):** Installing up to 1 MW commercial rooftop and 500 kW solar systems in priority hosting areas. Customers/third party providers will invest but incentives will be designed to highly encourage participation. Undertaken by the Central Victorian Greenhouse Alliance (CVGA).
10. **Concentrated Storage Impact (Demonstration):** Installing either network side or customer side batteries (with network operational control under certain conditions) co-located with solar from project 9. Undertaken by the Central Victorian Greenhouse Alliance (CVGA).
11. **Recommendations To Regulators (this project):** Reporting impacts of potential regulatory changes the study identifies to drive the economic, power and social outcomes sought. Undertaken by the University of Melbourne.
12. **Microgrid Assessment Tool Development:** Developing a tool that would help any similar regional town understand how well-suited they are for microgrids from the analysis performed in this study. Undertaken by Deakin University.
13. **GWM Water – Donald Industrial Site Feasibility Assessment:** Analysing the GWM-Donald industrial park site relative to other sites in the Powercor network for microgrid implementation. Undertaken by Powercor with ENEA Consulting.

Taken together, these sub-projects will not only inform the current considerations of whether a microgrid could help meet the needs and wants of the communities of Donald and Tarnagulla, but also collectively add to the knowledge base of what's required to establish other microgrids in other places.

Project 11 – Recommendations to Regulators *was undertaken by the University of Melbourne's Faculty of Architecture, Building and Planning. Dr Sangeetha Chandrashekeran was the lead researcher, and Dean Lombard was the project researcher. Prof. Pierluigi Mancarella and Carmen Bas Domenech from the University of Melbourne's School of Engineering, and Dr Larissa Nicholls from Monash University's Emerging Technologies Research Lab collaborated. For more information please contact Dr Sangeetha Chandrashekeran (sangeetha.chandra@unimelb.edu.au) or Dean Lombard (dean.lombard@unimelb.edu.au).*

Abbreviations and acronyms

AEMC – Australian Energy Market Commission

AEMO – Australian Energy Market Operator

AER – Australian Energy Regulator

ARENA – Australian Renewable Energy Agency

BESS – battery energy storage system

CAPEX – capital expenditure

CDR – Consumer Data Right

CPA – Community Power Agency

CVGA – Central Victorian Greenhouse Alliance

DELWP – Department of Environment, Land, Water and Planning (Victorian government department responsible for energy, renamed DEECA (Department of Energy, Environment and Climate Action) in 2023)

DER – distributed energy resources (e.g. rooftop solar, neighbourhood batteries)

DNSP – distribution network service provider

DR – demand response

DUoS – distribution use of system (network tariffs/charges)

ENA – Energy Networks Association

ESC – Essential Services Commission (Victoria)

FCAS – Frequency Control Ancillary Services

HV – high voltage (section of network)

LPG – liquified petroleum gas (propane)

LUoS – local use of system (network tariffs/charges)

LV – low voltage (section of network)

MV – medium voltage (section of network)

MW – megawatts

NECF – National Energy Consumer Framework

NEM – National Electricity Market

NEO – National Electricity Objective

NER – National Energy Rules

NPV – net present value

NUoS – network use of system (tariffs/charges)

OoLR – Operator of Last Resort

RAMPP – Regional Australia Microgrid Pilots Program

RoLR – Retailer of Last Resort

SAPS – stand-alone power system

SEC – State Electricity Commission

STPIS – Service Target Performance Incentive Scheme

SWER – single-wire earth return

TEC – Total Environment Centre

TNSP – transmission network service provider

TUoS – transmission use of system (network tariffs/charges)

VCR – value of customer reliability

VDO – Victorian Default Offer

VPP – virtual power plant (aggregated DER used for demand response)

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1 Executive summary

1. The objective of this project is to identify and articulate regulatory issues that impact microgrid development and make recommendations to regulators with respect to facilitating it. Key aspects include:
   a. Understanding community needs;
   b. Understanding microgrid capabilities and potential value streams;
   c. Considering the broader environment of the electricity system and how it is managed.
2. A working definition of a microgrid is needed. We propose:
   a. A distinct interconnected local energy system that is also connected to the wider grid;
   b. With its own generation and storage – which may be a mix of behind-the-meter and community or front-of-the-meter resources;
   c. That can operate in grid-connected or islanded mode; and
   d. That can actively balance and optimise local and network supply to benefit users.
3. The feasibility of a microgrid needs to be considered in terms of the alignment between what the community aspires to achieve from it, and the functions it can perform. Communities' ability to achieve many functions are constrained by the existing regulatory settings.
   a. Community values include emissions reduction, improved reliability and resilience, managing energy costs, local ownership or control of energy resources, and supporting local economic development.
   b. Functions could include accessing the wholesale market directly, providing ancillary and network services, and participating in a virtual power plant; as well as coordinating supply and demand within the microgrid to strike the right balance between use of microgrid and NEM energy resources for optimal community benefit.
4. Regulatory reform that fully enables the full suite of functions available to microgrids can maximise the value they can access in order to help offset the cost of meeting community needs while also providing broader system benefits (e.g., emission reduction, reduced system operation costs, etc.). Exploratory modelling undertaken for this project demonstrates that considerable value can be achieved, especially in conjunction with centralised control and coordination of microgrid energy resources.
5. Regulatory issues can be defined as **existential** and **functional** and exist on a spectrum from the minimum required for a microgrid to exist, to what's needed for maximum functionality.
   a. Existential issues include ensuring key aspects of energy regulation (such as consumer protections, safety, reliability, security and economic regulation of monopolies) can apply within.

   b. Functional issues determine the microgrid's access to value streams and include reviewing regulatory barriers to valuing market and network services and resilience investments.

6. **Consumer protections are vital** and well established in legacy energy regulatory frameworks. Ensuring they are incorporated into microgrid frameworks as foundational, rather than superficial, is critical to ensure that consumer outcomes are protected, and social licence is achieved.

7. **We've identified three regulatory frameworks that could enable microgrids** with minimal adjustments – the DNSP-led SAPS (stand-alone power systems), third-party SAPS, and embedded networks frameworks. These could be expanded to have microgrid-specific provisions or replicated with appropriate variations as new frameworks.

   a. Key issues for the DNSP-led SAPS framework include access of distributed energy resource (DER) operators and retailers to wholesale and system services markets, managing energy purchasing across islanded and grid-connected modes, enabling internal and external network services, and whether to allow a vertically integrated microgrid gentailer (retailer that also owns generation resources).

   b. Key issues for third party SAPS and embedded network frameworks include price regulation and access to retail contestability, allowing network charges, reliability and service standards, connection entitlement to the wider grid, and managing microgrid operator failure.

8. Our work has focused on the regulatory issues. There are also critical legal and equity issues that need to be addressed but fall outside the scope of this work. In particular:

   a. There is work to be done developing ownership and governance models for microgrids that realise community visions for shared ownership and benefit-sharing, and to mitigate risks. Community engagement and capacity building should be understood as core issues and explored in parallel with regulatory reform.

   b. Work is needed reviewing the distributive equity principles and frameworks inherent in regulation of DNSPs and reallocation of network capacity to users over time as we move toward a just transition to more decentralised energy resources, particularly connected to low-voltage networks.

9. The potential value of coordinated management of demand and supply within the microgrid is so high, that regulatory frameworks supporting maximum coordination of generation, network management, and energy purchasing and retailing are desirable. A rule change may not be required, but a framework review is probably needed. As such, our initial **recommendations** are:

   a. A clear regulatory definition of microgrids is needed.

   b. Regulatory reforms for distribution networks are required to properly value what microgrids can offer.

   c. A DNSP-owned microgrid framework is needed, based on the DNSP-led SAPS framework but allowing passthrough of price benefits from optimisation of generation, storage and demand within the microgrid and access to system markets.

d. An embedded microgrid framework is needed, based on the embedded networks framework but allowing local use of system network charges, interactions with system services and markets, and an operator of last resort scheme.

e. Appropriate energy consumer protections will be needed irrespective of the type of microgrid, to give consumers equivalent protections to NEM consumers, but adapted to suit the microgrid environment.

f. A framework for accrediting and overseeing community-benefit energy providers in microgrids may be useful, in which specific consumer protections might be varied. This would be informed by the project on developing ownership and governance models for microgrids proposed in 8a above.

g. A transition plan is needed to enable predictable regulatory change towards more cost-reflective network pricing when distributed generation, storage, and demand response are more ubiquitous and widely distributed. This would be informed by the project on distributive equity principles and frameworks inherent in regulation proposed in 8b above.

2 About Project 11: Recommendations to regulators

The purpose of *Project 11 – Recommendations to Regulators* is to:

1. Identify regulatory and market barriers to microgrids;
2. Articulate the regulatory changes that might be needed to implement microgrids;
3. Evaluate the potential impacts of making those changes; and
4. Recommend what changes to pursue, and how to pursue them.

To achieve this, the project was designed to undertake these key tasks:

1. Review the current regulatory framework, market rules, and market behaviours to identify aspects that prevent or constrain microgrids from being established or reaching their full potential;
2. Review the findings of other elements of the Microgrid Feasibility Study to identify where they are impacted or constrained by those regulatory or market barriers;
3. Consult with key stakeholders to interrogate the issues and clarify understandings and recommendations; and
4. Write a report (this one) with recommendations for action, and devise a communication and engagement strategy to inform and resource stakeholders.

Critical to this cross-cutting project is to understand in greater detail what the communities' needs, wants and values are; differences among and within the communities; and what specific problems they hope that the microgrid will solve. This is necessary to identify the most significant regulatory and market barriers and prioritise the changes required.

As well: it is useful to develop some understanding of the additional value streams accessible by the microgrids if changes to regulatory frameworks allow them. In fact, while *potentially* improving reliability and resilience (whose value monetisation represent an issue *per se*), establishing these communities as islandable microgrids – i.e., installing enough additional energy generation and storage to enable disconnecting from the wider grid and operating independently for extended periods – will incur capital costs that will flow through as increased electricity costs for the community. By also using the unique characteristics of a microgrid to sell services to the wider electricity system and find efficiencies through coordination, these additional costs can be reduced or even offset by revenue earned and economies found. While detailed economic analysis of this nature is outside the scope of the *Recommendations to Regulators* project, estimates of the potential value to the communities of regulatory changes add useful context so further modelling has been undertaken from the University of Melbourne's power systems team, which undertook *Project 8 – Economic and risk assessment*, on the potential value of some opportunities that would be unlocked by some of our proposed regulatory changes.

Market-based versus government-led approaches to microgrid development and regulatory reform

We note that there are two contrasting ways to approach microgrid development. The first is a market-based approach. This involves making incremental changes to the existing electricity market and its regulatory frameworks and using market-based incentives to develop microgrids. The ideal of competitive markets as the means to drive efficient pricing is at the heart of the current economic regulatory approaches in the electricity sector. A range of economic regulation tools are applied to DNSPs – which are spatial monopolies – that seek to mimic what a competitive market would do: for example, through benchmarks for the cost of capital and efficient investment practices. Under the market-based approach, regulatory reform is required to enable the functions available to microgrids and maximise value to consumers (defined broadly) whilst adhering to embedded principles (such as the National Electricity Objective (NEO)), existing industry structure and institutional arrangements.

The second approach is what we might term a green industry and regional development approach to microgrids. This would involve using state fiscal and regulatory authority to nurture and grow microgrids into the future, promoting and facilitating a just transition away from fossil fuels, and balancing trade-offs and conflicts between different interests in the electricity sector and beyond to facilitate a zero-carbon energy economy with substantial local generation. These priorities and strategies would be designed to overcome the existing structural barriers to investment in microgrids, many of which arise from legacy market design and rules based on centralised generation. The tools that could be used to do this include investment vehicles and investment targets – such as local generation and storage targets, green bond financing, public–public (e.g., state and local government) or public–community partnerships, revolving loans, targeted and block grants, and consumer subsidies. Regulation would be deployed to require the use of certain environmentally beneficial or locally-based technologies, based on well-established goals such as growing the market for local green goods and services. This extends beyond the established limits of current electricity regulation. Indeed, if microgrids and local generation are recognised as providing the enabling conditions for economic development at local and regional scales, then microgrids become part of regional economic development policy and are regulated accordingly.

In reality, in Victoria today, there are increasing elements of the second approach, but the first approach remains dominant in electricity regulation. For the purposes of this report, we have focused mainly on reform within the existing electricity regulatory framework which emphasises market-based approaches. We recognise that there is an alternative regional economic development policy approach that could be applied to microgrid development in Donald and Tarnagulla; however, this is not the dominant framing that we apply in this report on regulatory reform.

3 Findings from other projects

In undertaking this project, we reviewed all of the other sub-projects (except *Project 12 – Microgrid Assessment Tool Development*, because it was still underway) in order to understand the potential functionality, size, economics, and form of the possible Donald and Tarnagulla microgrids. This was to give us an indication of what aspects of the electricity regulatory framework were most relevant for the project.

We also reviewed other projects and papers concerning regulatory aspects of microgrids – in particular the work of the Monash Microgrid Project, which examined a range of issues relevant to developing microgrids in Victoria;[2] CutlerMerz's work with the Energy Networks Association (ENA) and the Total Environment Centre (TEC) on the potential of stand-alone power systems (SAPS) to enhance network resilience;[3] and the Australian Energy Market Commission's (AEMC) review of the regulatory frameworks for SAPS.[4] These have informed our analysis.

3.1 Donald and Tarnagulla Microgrid Feasibility Study project summaries

These are brief summaries of the goals and key findings of other sub-projects that were largely or fully completed when this project was being undertaken. Taken together, these projects outline the likely form and function of the potential microgrids and give some indication of the social, technical and economic framework within which they would operate. More detailed information can be found in the various project reports, available at c4net.com.au/projects/donald-and-tarnagulla-microgrid-feasibility-study.

Project 2 – Community engagement

To understand the communities' energy needs, the appeal of various trade-offs, what changes to current supply could be accepted and what behavioural change could be expected, and factoring these into the feasibility assessment and design of any microgrid solution. According to the nine people surveyed:

- Priorities are environmental sustainability, reliability, and cost.
- Cost is important but not the most important. Happy to pay a bit more for local benefits.
- Strong preference for local reliance (though not necessarily exclusive).
- Concern about reliability, especially for hospitals, and vulnerable groups.
- Retail choice is not important. Whatever works!

[2] Numerous documents available at https://www.monash.edu/net-zero-initiative/publications

[3] CutlerMerz (2020) *Opportunities for SAPS to enhance network resilience: Final Report* (https://www.energynetworks.com.au/resources/reports/2020-reports-and-publications/opportunities-for-saps-to-enhance-network-resilience/)

[4] AEMC, *Review of the regulatory frameworks for stand-alone power systems - priority 1*, Final report, 30 May 2019 and AEMC, *Review of the regulatory frameworks for stand-alone power systems - priority 2*, Final report, 31 October 2019.

- Want to share surplus solar within the community.

The project also delivered energy literacy training to community members; and noted that broader and deeper community engagement would be beneficial in better understanding the communities' needs and values.

Undertaken by Swinburne University and the Central Victorian Greenhouse Alliance (CVGA).

Project 3 – Network assessment

To assess the current and forecast status of supply to Donald and Tarnagulla, including grid and customer characteristics, demand peak, volume, events impact, known constraints, and power quality analysis.

- Both towns are on long feeders (from Bendigo Terminal Station) and there is little capacity to transfer load to other feeders or stations.
- Each feeder has around 1,700 customers with around 500 being commercial, industrial, or agricultural.
- Historically, maximum demand of both feeders has not exceeded their respective capacity ratings.[5]
- There is no augmentation planned in the near future.

Undertaken by Powercor.

Project 4 – Area hosting capacity assessment

To model (for each town) different hosting scenarios for self-generation including solar, diesel/gas gen-sets, storage and demand response options while accounting for network constraints. Scenarios were *grid-connected* (with some backup capacity), *islanded* (stand-alone system with no grid connection and more storage and generation) and *virtual power plant* (grid-connected and islandable, with more generation and much more storage than the other scenarios and forecasting load and generation to optimise these resources).

- Grid-connected scenario is most cost-effective.
- Islanded scenario has higher reliability.
- Virtual power plant scenario provides the most energy security and is cost-effective but has a high capital cost.
- Both towns have more consistent voltage when islanded due to voltage support from the back-up generator.
- Residential batteries are great for absorbing surplus generation, while community batteries are most effective at the end of a feeder to deal with voltage issues.

Undertaken by RMIT University.

Project 5 – Islanding design and cost analysis

To define the optimal location for islanding point, design elements, the cost of doing so (hardware, installation and ongoing operational), and network connection assessment.

[5] N rating: Donald's feeder CTN006 has an N rating of 9.2 MVA; Tarnagulla's feeder MRO007 has an N rating of 10.4 MVA

- Grid-connected operation is most cost-effective, but reliability is higher in islanded mode.
- Valuing reliability according to the *value of customer reliability* (VCR) for regional Victorian customers, some islanded scenarios produce a modest net benefit.
- Islanded microgrids can meet the electric load demand reliably and continuously under different operation and investment scenarios.
- Fully eliminating grid-connected reliability issues (≅ 5 days of outage per year) would require considerable investment and lead to up to 5x more expensive electricity.

Undertaken by Federation University in partnership with RMIT University.

Project 6 – Stakeholder impact investigation

Develop a trading model and simulated trading platform for off-grid microgrids, to understand critical customer needs, ability to prioritise supply ranking when islanding (e.g., prioritising supply to hospital, life support premises, commercial/residential considerations), attractiveness of microgrids for businesses, and regulatory requirements for de-energising and re-energising.

- PV, batteries, and diesel gensets best meets security, cost, and sustainability needs when energy security and reliability are prioritised.
- Energy cost when islanded for an extended period is high but may be offset by savings from self-generation at other times.
- Load shedding or shifting for non-critical loads can improve security and cost when islanded.
- Numerous regulatory changes will be required.

Undertaken by Swinburne University.

Project 7 – Microgrid impact study

Model the economic, reliability and resilience impact in grid-connected and islanded modes and under different operating conditions to assess the options, risks and benefits of specific control strategies.

- Less supply capacity than demand may be available when islanded, unless more generation is added.
- More diesel storage capacity is required to support islanded operation.
- Islanding Donald led to overvoltage upstream and undervoltage downstream.

Undertaken by the University of Melbourne.

Project 8 – Economic and risk assessment

The aim was to examine the techno-economic implications of the proposed microgrid, understanding the main benefits and costs to each stakeholder and whether a microgrid is commercially feasible for the different stakeholders – including identifying value potential created, investment required, alternatives (including network storage etc.) and community effects (impact on all grid-users) and risks.

- Significant economic benefits can emerge from purchasing energy wholesale, DER wholesale market arbitrage, and DER participation in contingency FCAS.
- Increased reliability and resilience are other tangible benefits, but not directly monetizable.
- Peak demand reduction and provision of network services can also be delivered but need regulatory change to capture value in the community.

Undertaken by the University of Melbourne and Federation University.

Projects 9 & 10 – Concentrated generation and storage impact

Determine community energy supply and usage requirements and assess the community desire for new energy solutions. Design and install up to 1 MW commercial rooftop and 500 kW solar systems in priority hosting areas, and either network-side or customer-side batteries (with network operational control under certain conditions) co-located with some of those solar installs. Customers/third party providers will invest but incentives will be designed to highly encourage participation.

- Developed solar and battery bulk-buy programs for homeowners and businesses (nothing for renters).
- Ten $500 rebates were given for solar installations in the Donald area – two to businesses and eight to households).
- Tarnagulla Urban Fire Brigade was granted $5,000 and Donald Learning Centre was granted $10,000 for installation of battery storage to complement their solar.

Undertaken by the Central Victorian Greenhouse Alliance (CVGA).

Project 13 – GWMWater site assessment

To identify suitable microgrid sites within Powercor's network and compare the costs and benefits of a Donald microgrid designed to primarily benefit GWMWater and the adjacent industrial precinct with these other sites.

- Possible value streams for grid-connected microgrids are FCAS and energy arbitrage (accessible by non-DNSP operators of community DER); reduced line losses and network CAPEX deferral (realisable by DNSP); and bushfire risk reduction and reliability (beneficial to community and the DNSP).
- 55 sites in Powercor's network are suitable for a microgrid. 12 yield a net benefit (positive NPV), and a smaller (1.6 MW) Donald microgrid centred around GWM is the 11th of these (ranked by NPV highest to lowest).
- A larger (2 MW) microgrid was also modelled but has a negative NPV.
- Reliability issues on the network appear as the key driver of the positive NPV. CAPEX deferral is not significant.
- Battery costs are also a key factor – diesel fuel cost is not.
- Smaller (1.6 MW) Donald Microgrid has positive NPV if RAMPP (ARENA's Regional Australia Microgrid Pilots Program) funding is used and non-STPIS (i.e., cost pass-through) reliability events are included.
    - Decrease in battery costs or increase in reliability benefits leads to significant improvement in net benefit (NPV).

  - Some benefits (e.g., non-financial community benefits) and costs (e.g. installation costs) are not included in this analysis.
- Decarbonisation is an objective for GWM; but diesel generators are part of the modelled microgrid.

Undertaken by Powercor and ENEA Consulting

Consolidated findings from all projects

- Community members surveyed wanted **greater reliability** – especially for the hospital and vulnerable groups – and **more self-reliance** such as sharing surplus solar within the community. They were prepared to pay a little more for these benefits. **Retail choice** was less important to them than getting these benefits.
  - Deeper and wider community engagement will build a better understanding of community goals and values, especially with respect to variance within and between communities, and prioritisation of values.
- Under the current regulatory framework, a microgrid could[6]:
  - help stabilise local grid **voltage**.
  - deliver lower energy costs through **direct wholesale purchasing**.
  - earn revenue from **VPP participation**, **wholesale market arbitrage** and **provision of ancillary services**.
  - enable coordination of storage, loads and generation to **reduce peak demand** and prevent insufficient minimum demand.
  - significantly **increase reliability and resilience**.
- With regulatory changes, a microgrid could also earn revenue or reduce energy costs by providing **network services** to the DNSP.
- A fully islandable microgrid requires significant investment cost that needs to be recouped through energy prices – but the magnitude of this depends on the degree of islandability (i.e., how long and at what capacity it can island), its ability to access available value streams, and potential additional benefits if further value streams are unlocked.
- The significantly greater cost for fully islandable town-sized microgrids makes it unlikely these could be DNSP-led stand-alone power systems (SAPS) under the current regulatory system. This could change if **resilience is fully valued** in the regulatory framework, or if other regulatory changes can better reflect value unlocked by some microgrid-enabled functions or account for non-quantifiable community benefits in a way that does not disadvantage community members who will not or cannot pay higher prices for these benefits.

[6] These all bring tangible value but some can't directly offset costs without regulatory change, and others may be able to access additional value with regulatory change.

4 Defining microgrids

Microgrids are not defined in our current regulatory framework, and the term is defined differently (and with varying degrees of clarity) in different papers, projects, and other places where microgrids or energy communities are discussed. For the purposes of this project, a microgrid needs to be clearly defined to distinguish it from other small energy networks or entities such as stand-alone power systems (SAPS) and embedded networks.

For our purposes, its key characteristic is that **a microgrid has the ability to operate when connected to the larger grid, as well as to disconnect from the grid and still operate as a stand-alone system.** This is the most significant thing that distinguishes a microgrid from a SAPS (an independent network that is not connected to the main grid) and an embedded network (an independent network that is connected to the main grid at a single connection point). And it aligns with a definition from the US Department of Energy:

> *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.*[7]

Hirsch *et al.*[8] note that this definition is silent about the size of the distributed energy resources[9] or the types of technologies used, and they identify some key characteristics:

- it's a distinct system distinguishable from the rest of the distribution system;
- has distributed energy resources connected in proximity and controlled in concert locally, not remotely;
- can function even when not grid-connected, and irrespective of the larger grid; and
- constitutes a single controllable load point, from the perspective of the grid operator.

The Monash Microgrid Project proposed a definition, for regulatory purposes, that also encompasses some aspects of a microgrid's purpose:

> *A local electricity supply system that delivers a bundle of services that must include:*
>
> - *dynamic control of load, local renewable generation and/or storage;*
> - *active integration of local and network supply;*
> - *optimisation of electricity supply and use to benefit users; and*
> - *monitoring the balance of customer use between local and grid supply.*[10]

[7] Ton DT, Smith MA. The US Department of Energy's microgrid initiative. Electr J 409 2012;25:84–94. Cited in A Hirsch, Y Parag, J Guerrero *Microgrids: A review of technologies, key drivers, and outstanding issues*, March 2018

[8] A Hirsch, Y Parag, J Guerrero *Microgrids: A review of technologies, key drivers, and outstanding issues*, March 2018

[9] However, in practice microgrids are intended and implemented in sizes compatible with low-voltage or small medium - voltage substations, so from a few hundreds of kilowatts to a few megawatts.

[10] Monash University *Submission to DELWP Embedded Networks Review Issues Paper*, 26th February, 2021: p. 6

In this project we are assuming a microgrid has key characteristics based on the above definitions:

- **a distinct interconnected local energy system** that is also connected to the wider grid and acts as a single controllable entity with respect to the grid;
- **with its own generation and storage** – which may be a mix of behind-the-meter and community or front-of-the-meter resources;
- **that can operate in both grid-connected *and* islanded mode**; and
- **can actively balance and optimise local and network supply** to benefit its community.

This definition was largely accepted during our consultation with a range of stakeholders. On one aspect, though, there was some contention – whether the ability to operate independently of the grid (i.e., in islanded mode) is a defining feature of microgrids.

Some stakeholders considered that being a *distinct interconnected local energy system* with the ability to *actively balance and optimise its own energy storage and generation resources* with those of the larger grid to *benefit the microgrid's community* was the distinctive character of a microgrid, and that islandability was not necessary. From this perspective, a microgrid is a set of connected energy resources proactively operated and coordinated together to serve a distinct community and reduce its reliance on the wider electricity grid. Adding weight to this view is the likelihood that most islandable microgrids would almost always be grid-connected – islanding only when compelled by circumstances (such as a grid outage).

While we find this definition compelling, it could also be applied to an embedded network – and indeed, some embedded networks with their own energy resources refer to themselves as microgrids,[11] and the Victorian Government used the term when it exempted "buildings that use renewable energy microgrids to deliver low-cost renewable energy to apartment buildings" from its embedded networks ban.[12] After much consideration our view remained that **islandability is warranted in a microgrid definition**, for two main reasons:

- islandability is what distinguishes a microgrid from an embedded network; and
- community interest in microgrids is frequently driven by the desire for more reliability and resilience[13] – functions that require islandability.

Even if a microgrid never actually operates in islanded mode, islandability is a key aspect of its raison d'etre, identity and functionality.

Islandability brings its own challenges, of course. Many of the regulatory issues with microgrids arise because of their ability to separate from and re-join the grid. With the AEMC's SAPS review now complete, there are established or nascent regulatory frameworks for energy networks connected to and separate from the NEM, and owned by DNSPs or third parties – but not for networks that encompass both of either of those binaries.

[11] See, for example, https://gemenergy.com.au/embedded-network-microgrid/ and https://www.madimack.com.au/blog/what-are-embedded-networks-and-microgrids.

[12] https://engage.vic.gov.au/embedded-networks-review

[13] This was clear in the community engagement done as part of the Donald and Tarnagulla Microgrid Feasibility Study and is discussed further in the section on delivering community values, on page 17 below.

Additionally, islandable grids raise unique governance issues. These are all discussed in the section on *Capacity building, ownership, and governance* on page 45 below.

4.1 Purposes and functions of a microgrid

There are two distinct ways of considering what a microgrid might do and why:

- what the community needs and wants for itself in relation to its energy supply and demand; and
- what functions could a microgrid serve both within itself, and in the wider energy system.

The former comes from the people living and working within the microgrid and how they want to live and work; the latter is a techno-economic question and is based on what is possible and useful – noting that 'useful' is defined as much by what is expected and valued as by what is functional in a techno-economic system. Looking at them together it is clear that they overlap and in particular that the latter serve and enable the former.

The microgrids under consideration are located where they are because of community interest in having a microgrid. So the overarching approach we are taking in this project is to prioritise the communities' objectives. Any potential microgrid should deliver their residents' (including businesses') objectives as much as possible, with constraints being the limits of what is physically possible, economically feasible and fair, and those set by the trade-offs between the communities' different objectives. (For example, two community objectives might be to reduce emissions, and to manage energy prices within a reasonable range – these put limits on each other, and on other objectives.)

Regulatory issues also pose constraints – some things are not possible under the current regulatory framework, and this has a bearing on the economics of a future microgrid. But because our purpose is to identify those constraints and other regulatory issues, we will both acknowledge them and treat them as permeable for the purposes of envisioning the microgrids' full potentials.

A central dynamic is the economic reality – attaining the level of resilience against outages that the community desires will increase their energy costs due to the amount of redundancy of generation and storage required to power the towns in islanded mode for extended periods. Against this, though, can be set the potential revenue from value streams that the microgrid can access due to its distinctive functionalities – providing regulatory settings and market structures allow this. As part of this project, we undertook some exploratory modelling of the potential value of accessing certain value streams that are partly or fully constrained in the current regulatory and market framework – see section 4.3 *The value of regulatory reform* on page 26 below.

There are both cost and risk allocation questions associated with a microgrid and it is important to foreground who bears the costs and risks. Different microgrid options will involve different cost and risk allocations; and regulatory reform could reshape those allocations with potential benefits for microgrid proponents. Questions of scale and reallocation across the network are therefore central to the distributional aspects of this project. We will not be modelling the allocative implications of the proposed regulatory changes as it sits outside the scope of this part of the study, and indeed the study as a whole. Nonetheless, we recognise that this is work that needs to be undertaken to have an informed discussion about microgrid feasibility in these towns down the track.

Microgrid purposes – delivering on community values

Project 2 – Community Engagement interviewed nine community members and identified the values pertaining to their energy supply that are outlined below. When consulting on our draft findings, we engaged with three more community members and gained some further understanding of their aspirations. Together these can be interpreted as a non-exclusive set of possible objectives for a microgrid or other community energy project.[14]

It's important to recognise that the people interviewed and engaged with do not constitute a group that can be considered representative of either community – some wider consultation is advisable. However, the values and concerns expressed by them are consistent with findings from other community energy projects, as documented by the roundtable discussion held as part of the project.[15]

This is our interpretation of these expressed community values. They are in no particular order, as we have no information as to how these values are prioritised by different people or groups within the communities, nor how widely and to what extent they are held.

Environmental sustainability (decarbonisation)

- Reducing emissions by reducing reliance on fossil-fuel generated electricity
- Generating more renewable electricity on-site, using:
    - community energy (shared renewable generation)
    - private solar shared with the wider community

Realising these objectives will at some point require increasing distributed energy resources (DER) hosting capacity within and around the communities – so this is another, implicit objective.

It's also worth noting that while community members talk about electricity when discussing emissions reduction, LPG (propane in steel bottles or large tanks) is also used in the community – domestically and industrially. In particular, some community members have told us that industrial plants in Donald use LPG because there is insufficient network capacity to serve those loads with electricity. Any work with the communities on emissions reduction will need to consider the emissions of LPG usage and, ultimately, potential for fuel substitution.

Additionally, we note that most designs and models for the microgrids in this Feasibility Study include diesel generators as either part or all of the microgrids' generation. It is important that this issue is made clear to community members, especially in the context of the value set by some on emissions reduction.

14. J Farmer & M Schleser (2021) *Microgrid Feasibility Study: Interviews – Donald and Tarnagulla (Stage 1 report)*, Swinburne University of Technology Social Innovation Research Institute.

15. M Scleser & M Wheeler (2022) *Report: Microgrid online roundtable discussion*, University of Technology Social Innovation Research Institute.

More reliability and resilience – especially for essential services and vulnerable groups

- Being able to meet its own electricity needs if there is an outage on the grid, which implies:
    - sufficient generation and storage to meet all or some of the communities' demand for a given period of time
    - islandability: the ability to operate independently of the wider grid
- Possibly, being able to ration electricity during long-duration outages to serve those most in need when there's not enough to go around, which also requires:
    - a process for agreeing and setting parameters for this
    - a system to action it.

The second point – being able to ration electricity – is something implied by some comments in the interviews, and is sometimes proposed in community energy discussions with other communities. Further engagement is needed to determine the extent to which it is held and understood in the community.

Manage (reduce or prevent from rising) costs

Many people believed a microgrid or other community energy project could help moderate rising energy costs – which seem particularly egregious because of the reliability issues with both towns' supplies, which are typical for small communities toward the end of rural feeders. Some ways of managing costs through a microgrid or other community energy initiative could be:

- increase hosting capacity and install more private DER
- community energy and non-profit community retailer which could
    - purchase from the wholesale market when local generation is insufficient
    - arbitrage local DER generation in the wholesale market
- earn revenue from selling a range of system services

Our further techno-economic analysis following the approach of Project 8 also shows that coordination of demand and supply within the microgrid enables more strategic exchange with the wider grid and energy market, yielding further cost reductions. This may require a proactive microgrid energy provider that handles retail, storage and generation. This is discussed further in section 4.3 *The value of regulatory reform* on page 26 below.

Local ownership or control of energy resources

Many members of the community placed a premium on the "local-ness" of electricity generation. Some people in Donald expressed a desire to have a locally based energy supplier, as was the case until the early 1960s;[16] and in both towns there was a certain pride derived from the significant investments in rooftop solar and other private DER.

This translated into a sense of ownership of the electricity and a desire for greater control over how that electricity is distributed. Local community members were seeking to derive more local benefits from those investments. They are also seeking to share energy locally in

[16] https://donaldhistory.org.au/welcome/donald/

a way that is equitable and prioritises community members who are vulnerable to energy hardship and have the greatest need.

In one sense, local energy sharing happens automatically (albeit passively) when DER is in the community and especially if a microgrid is managed in order to maximise benefit to the community. But to make it more tangible for the community, this could entail:

- a system for active peer-to-peer sharing/trading
- a system for reporting local share of generation

In another sense, there still remain local benefits – network support through minimum and peak demand management – that cannot be fully captured due to regulatory constraints. Local use of system (LUoS) network tariffs could be a way of reflecting the economic benefits of high levels of local generation. We note that this raises the more complex question of whether more cost-reflective tariffs should also be used for electricity consumed from the wider grid.

As the project has progressed, some interest has been expressed in a local government-owned energy provider; or the potential of the new State Electricity Commission (SEC) to provide generation and retail services as a not-for-profit community benefit provider. Certainly community-oriented governance and value sharing will be needed if a microgrid is to offset higher energy costs with revenue from accessing internal and external value streams. This is discussed further in the section on governance on page 45 below.

Support economic development

Some of the strongest advocates for a microgrid in Donald saw it as a way to drive local economic development and bring new investment to the town. There were two aspects to this:

- Increased reliability and capacity could both enable existing businesses to expand, as well as attract new businesses to come to Donald. Members of Donald's business community told us that some local businesses had to switch from electric to gas-fuelled equipment due to the limited capacity of the town's electricity supply.
- A microgrid could be seen as a demonstration project or "living laboratory" that showcases the innovation and community cohesion in Donald and puts the town "on the map", leading to greater attention and investment.

We note that such economic development goals can change both the rationale and calculus of costs vs benefits of a microgrid by expanding the horizon, both spatially and temporally, of what a microgrid sets out to achieve. Also, local economic development goals are governed by state government planning, economic policies and development regimes, rather than the narrower field of electricity regulation.

Considerations when assessing community objectives

Further engagement with community members has confirmed that while the above are valued in the community, different community members prioritise them in different ways, and for different reasons. For example, some people value emissions reduction for its own sake; others refer to it in connection with the knowledge that state-wide emissions reduction targets are becoming more important and local industries will need to align; and others value the potential of renewable generation and storage primarily to enable their town to ride out grid outages.

It's also worth noting that some interviewees indicated that while reducing costs was a significant objective, they may be prepared to pay a little more to enable other community benefits. Again, the extent to which this view is held and the magnitude of cost increases considered acceptable would need to be determined by more extensive community consultation.

Establishing a microgrid will have certain implications for the community and how it would continue to engage with the state-wide electricity system, and these implications vary according to exactly how the microgrid might be established – both physically and technically, and in the regulatory approach taken. We have identified two core considerations that are relevant to assessing the optimal path through these possibilities:

The role of energy retailers

Some community members surveyed said that retail choice was not a priority for them and they were willing to sacrifice retail choice in order to achieve a microgrid that met their needs for cost and reliability. This seems consistent with some other research on consumers' views on retail energy markets.[17] If we consider that the objective of retail competition in energy is to provide good *prices* for consumers, we could consider other ways to achieve good prices if alternatives to retail competition are beneficial in microgrids – for example, price benchmarking using an instrument such as the Victorian Default Offer (VDO).

Achieving community values and objectives

There are a range of other measures, besides a microgrid, that could achieve many of the community values and objectives. For example, a battery trial with innovative tariffs could address some reliability concerns and enhance local use; especially if combined with dynamic operating envelopes and better load orchestration to improve hosting capacity.

4.2 Microgrid functions – providing local and system services

Our review of the other sub-projects identified a number of functions or services, all used in assessing design parameters and calculating economic viability. Some services, such as voltage and demand management within the microgrid to maximise DER hosting capacity, are needed to directly meet community objectives and are assumed to be a necessary part of operating the microgrid. Others provide services to the wider grid or wholesale market. These latter services are not expected to be identified by the community as objectives for the microgrid, but they are still relevant to community objectives because the revenue

[17] For example, the Essential Services Commission's 2020–21 Victorian Energy Market Report found that "most participants [in a study analysing their experiences choosing a retailer] found the process of comparing different plans overly complex… felt overwhelmed by the number of options available… several participants thought the perceived effort outweighed the reward." (Essential Services Commission 2021 *Victorian energy market report: 2020–21* 29 November: p. 13)

generation potential of a microgrid affects its ability to cost-effectively deliver to the community. Setting up a microgrid capable of powering a community independently of the grid during an extended grid outage requires considerable investment that needs to be recouped – raising an additional energy cost that needs to be met by the community. **Being able to defray this cost with revenue earned from providing services to or across the grid could mean that some community objectives can be met with negligible or modest additional cost.** And, since one of the community objectives is to reduce energy costs, it could be argued that they are integral to meeting community objectives. This is the dominant lens through which we conduct the analysis from hereon in.

Nonetheless, we note that if the rationale for enabling microgrids is based on logics of regional development or stimulating local economies, then a broader set of criteria could be used to assess the viability of microgrids in Donald and Tarnagulla. Were these microgrids deemed viable on such grounds, then regulatory reform would be necessary to enable such a policy position, having regard of course to techno-economic feasibility and critical questions of welfare distribution through cost-reallocations.

Purchase energy wholesale

A single retailer within the microgrid could purchase electricity directly from the wholesale market. Depending on the extent to which it can coordinate with the microgrid's own generation and storage, it could purchase at a relatively low average price and bring that value to the microgrid.

To do this, a retailer must be able to able to operate within the microgrid as a majority or monopoly retailer and register with AEMO as a market participant. May also be possible for several smaller retailers within microgrid, with sufficient coordination of demand and supply.

Wholesale arbitrage of DER

The microgrid's DER operator(s) or a large retailer working with the DER operator(s) within the microgrid could deploy DER in response to wholesale market pricing as a priority over directly serving local needs first. Depending on the extent to which the DER operator(s) and retailer(s) can coordinate with each other, this could bring additional value to the microgrid.

To do this, the entity must be able to register with AEMO as a market participant.

Contingency FCAS and other ancillary services

The microgrid's DER operator(s) could offer contingency FCAS (frequency control ancillary services) to the ancillary services market earning revenue and bringing that value to the microgrid. A microgrid might also be able to trade in emerging ancillary services markets (such as inertia) when they are established. To do this, the DER operator would need to register with AEMO as a demand response service provider.

Network services

The microgrid could deliver a range of services to the surrounding network, including **voltage and peak demand management** (via demand response and internal voltage management), **bushfire risk mitigation** (by islanding on high-risk days to enable de-energisation of lines), and **CAPEX deferral** (through a combination of network services and generation coordination and investment).

The Victorian government has previously considered establishing a network services market. This would probably be required if the microgrid is not DNSP-owned – though a contractual agreement between a DNSP and a microgrid owner/operator might be sufficient. Additionally, changes to the regulatory framework for DNSPs to better capture the value of non-network services would probably be required.

Further: as noted above, there may be some capacity constraints experienced by microgrid customers that do not meet the criteria for a DNSP to consider them for an upgrade project. A microgrid could unlock this capacity in the same manner as providing network services as described above, and this would provide value to the community but not be quantified as a CAPEX deferral service or non-network solution. In the same way, the extra capacity enabled by a microgrid could lead to a reduced need for future network upgrades, leading to reductions in network costs for all customers over an extended period of time.

Participate in a Virtual Power Plant

A microgrid could provide any of the above services as part of a virtual power plant (VPP). This would require the microgrid DER operator(s) and retailer(s) to coordinate, or for a VPP within the microgrid to participate as a single customer in a larger VPP.

Summary table: Opportunities for microgrids to reduce costs or earn revenues

Revenue opportunity	Requirements
Purchase energy wholesale	Retailer(s), registered as a market participant, and operating as a majority or monopoly retailer within the MG (or coordinating with others).
Wholesale arbitrage of DER	Retailer(s), registered as a market participant, and operating as a majority or monopoly retailer within the MG (or coordinating with others).
Contingency FCAS and other ancillary services	DER operator(s) registered with AEMO as a demand response service provider.
Network Services	DNSPs need to value the services a MG provides to the network. To enable this may require a network services market OR better valuation of non-network services in DNSP regulatory approach
VPP Participation	Microgrid DER operator and retailer(s) to coordinate, or for a VPP within the microgrid to participate as a single customer in a larger VPP.

4.3 The value of regulatory reform

The University of Melbourne's power systems team undertook the economic and risk assessment studies for the Donald and Tarnagulla Microgrid Feasibility Study (Project 8), examining the techno-economic framework to determine opportunities to derive value. A key finding was that investment in a microgrid to improve reliability and resilience (to maintain power during short and extended outages – i.e., operate in islanded mode) could also yield considerable benefits during normal (grid-connected) operation. We thus undertook here some additional provisional modelling to assess the potential value of functions and services unlocked or enhanced by regulatory reform. This is a brief overview of the modelling and its key findings. For more detail refer to the full report in Appendix 2.

The microgrid operational model developed in Project 8 *Economic and Risk Assessment* was used to indicatively quantify the impact of a number of scenarios in which value could be accessed under specific regulatory frameworks or through regulatory reform. More details on the model can be found in the Project 8 report.[18] The main attributes and assumptions of the microgrid operational model are:

- The inclusion of the MV (medium voltage) network of each town and relevant operational constraints that impact the value the microgrid can provide to each town.
- The inclusion of different system-level and local value streams using sufficient time granularity that allows the model to capture extreme conditions where microgrids can provide significant value.
- Consideration of network investment cost recovery by including the network use of services (NUoS) charges that customers are subject to. Therefore, the underlying assumption is that the DNSP or a different equivalent entity owns the network assets in the microgrid and is in charge of the operation and maintenance of those assets.

The model was used to assess the impact of different approaches to providing some key microgrid functions:

- Operation of centralised or privately-owned DER
- Provision of energy to the community
- Provision of energy and frequency control ancillary services (FCAS)
- Managing peak demand through network tariffs
- Supply local energy demand during extreme weather events
- Provision of network services to the upstream grid

Results are summarised below.

Centralised DER

This study compared the performance of a single centralised battery energy storage system (BESS) operated to minimise retail energy charges for the whole community, and the same

[18] P. Mancarella, C. B. Bas Domenech, and A. De Corato, "Project 8 : Economic and Risk Assessment – Part I," Melbourne, 2023.

capacity in distributed privately-owned BESS operated to minimise retail energy charges for each customer.

It found that ***total energy costs for the community were materially lower with the centralised system****.*

It must be noted that the study only considered the MV network, and customers were aggregated at MV transformer. More precision could be achieved by including the LV (low voltage) network and each specific customer in the modelling.

Energy provision

This study considered three different scenarios with a centralised BESS providing energy arbitrage (selling electricity to the market when prices are high and buying it back when prices are low) to the community:

1. operating independently of community DER and demand and arbitraging with the wholesale market;
2. coordinating with community DER and demand and arbitraging with a retail time-of-use tariff at the connection point with the wider grid; and
3. coordinating with community DER and demand and arbitraging directly with the wholesale market.

It found that there is ***significant value in coordinating centralised DER with community demand and privately-owned DER****, especially when interfacing directly with the wholesale market.*

Two things must be noted:

- Wholesale price exposure presents opportunities and risks, as prices fluctuate from very low (and even negative) to very high. Further analysis is required to better assess the net outcomes (and risks) from being exposed to wholesale market prices. The comparison between Donald and Tarnagulla suggests that larger communities are more likely to find a net benefit, possibly at limited risk, in wholesale market exposure.
- A microgrid DER operator would share this value with the community by offering a competitive retail tariff (i.e., materially lower than NEM retailers). It would face the same spot prices, market fees and other unavoidable costs as regular NEM retailers, but would also have greater control (and predictability) over supply and demand within a known, geographically-connected community. Could such a retailer find sufficient economies to be viable while sharing its savings with its customers? More detailed modelling and retailer information are needed – as is further exploration of the ownership, governance and risk mitigation issues involved in a retailer operating for community benefit.

Providing energy and FCAS

Combining participation in the frequency control ancillary services (FCAS) market with energy provision to the community was assessed with four scenarios – the three above with direct FCAS participation included, and a fourth using coordinated BESS and community DER at the retail level plus participation in a virtual power plant (VPP) for FCAS access.

It found that given the current local demand and generation conditions of Donald and Tarnagulla, while ***FCAS participation could provide some additional benefit****, the value of the benefit was similar across all energy provision scenarios.*

It must be noted that capacity of a microgrid to provide FCAS is limited by the surplus capacity of private DER in the community after meeting demand and storage requirements, especially with the VPP scenario. Further analysis is needed to better understand the potential benefits at different DER capacities.

Managing demand with network tariffs

A number of studies were undertaken assessing different types of network tariffs, at both the connection point and within the microgrid, to understand their impact on energy costs and minimum and peak demand.

It found that to send the right signals to reduce peak demand and allocate costs fairly, ***considerable nuance is required in how tariffs are structured and where they are applied****. In general, cost-reflective tariffs within the microgrid – including special tariffs for community batteries – and at the connection point with the wider grid are beneficial.*

It must be noted that the application of such nuanced tariff structures has cost reallocation implications across the grid as a whole, and this needs to be taken into account in analysis.

Additional benefits of reliability investment

Previous work undertaken by *Project 8: Economic and risk assessment*[19] quantified the techno-economic benefits of having centralised DER in place to reduce the impact of outage events in the community.

It found that ***increased reliability from investing in centralised DER can provide significant value to the community both during outage events and while grid-connecte****d. Therefore, it is highly relevant that this value stream is included, with the appropriate framework to enable DER to have an emergency response to supply the local demand during these events.*

It should be noted that there are limited opportunities to monetise this value stream without regulatory change – DNSPs could reduce exposure to penalties for missing service targets, and communities spared cost pass-through from recovery expenditure after major outages, but the existing regulatory framework does not explicitly value expenditure to improve resilience from major events.[20]

[19] P. Mancarella, C. B. Bas Domenech, and A. De Corato, "Project 8 : Economic and Risk Assessment – Part I," Melbourne, 2023.

[20] For a more detailed discussion of this see CutlerMerz, ENA, & TEC (2020a) *Opportunities for SAPS to enhance network resilience: Final Report October 2020 and* CutlerMerz, ENA, & TEC (2020b) *Network Resilience – Potential benefits of a requirement to provide for resilience: Final report 23 December 2020*.

Providing network services

Provision of congestion management and voltage management services was studied. A major issue in undertaking this aspect of the analysis is that there is no market or general arrangement for centralised DER to provide network services. As such, the modelling made significant assumptions concerning the value of network services. For congestion management, a demand response (DR) service was generated using data on payments for and frequency of DR events from other Victorian DNSPs. For voltage management, United Kingdom prices on reactive power support were considered as a proxy ($5.6/MVArh). It assumed that reactive prices will be non-zero and negative during high solar generation to promote reactive power absorption and reduce voltage rise, and non-zero and positive during evening peak demand conditions to promote reactive power injection to reduce voltage drop issues. It must be noted the purpose of these studies was not to propose a framework to value network services, but to demonstrate the ability of the community to provide these services and receive value. It may also open a discussion on how network services might be valued more broadly in our energy system.

*It found that **centralised DER can be operated to provide valuable network services** (i.e., congestion and voltage management) to the upstream grid. Additionally, if these network services are required, **significant revenues could be accrued by the community**, improving its net position.*

Further studies are needed on the extent to which network services might be useful on the feeders servicing Donald and Tarnagulla, and their value, in order to provide more accurate estimates of the potential benefits for the community. Nevertheless, the potential for a community with centralised DER to provide network services should not be disregarded. There is a significant potential technical benefit in managing network constraints – especially as distributed generation and storage becomes more ubiquitous – and if the DNSP regulatory framework is reformed to better value non-network solutions, it could potentially result in avoided capital investment for network reinforcement and thus lower energy costs for all customers.

5 Regulatory issues

There are two types of regulatory issues that need to be understood. **Existential** issues pertain to the very existence of the microgrid. The current regulatory framework (both the Victorian and national frameworks) does not identify microgrids nor regulate them *per se* – rather, some of their activities are covered by certain aspects of the regulatory framework, and others are either prohibited or unregulated. For microgrids to be a part of the energy landscape requires them to be appropriately defined and regulated under the national and state-based frameworks.

Functional issues pertain to certain functions a microgrid might perform in the context of the wider energy system. A microgrid could exist without performing these (technical) functions but could be falling short of its potential to provide value to electricity users within the microgrid, and to the wider electricity system. For example, there could be a regulatory framework that defines and allows for microgrids to be established; but these microgrids might not be able to make full use of their ability to provide network services without a regulated network services market.

Below, we structure our discussion of regulatory issues under the categories of existential and functional.

5.1 Summary of key regulatory issues

These are the key regulatory issues that need to be implemented for microgrids to be established and deliver value.

Existential issues

The broad categories of regulation in the National Energy Rules and associated instruments will need to be addressed in any regulatory framework for microgrids. The AEMC identified these key areas of energy regulation during its *Review of the regulatory frameworks for stand-alone power systems*: [21]

- **Registration and licensing**
  Covering eligibility criteria to provide assurance that service providers are 'fit and proper', and to provide a means for the application of further regulatory obligations, as well as covering supply continuity.
- **Access and connection**
  Comprising obligations to supply, connect and/or provide access.
- **Economic regulation**
  Covering regulation of prices charged or revenues earned by the service provider for supply, connection and/or access.
- **Consumer protections**
  Including protections for vulnerable consumers and preventing unfair practices or unscrupulous behaviour.

[21] AEMC, *Review of the regulatory frameworks for stand-alone power systems - priority 2*, Final report, 31 October 2019

- **Reliability of supply obligations**
  To support adequate and efficient levels of reliability.
- **Network operations**
  Including system security and technical standards, in addition to metering and settlement.
- **Safety**
  Standards governing the safe supply of electricity to consumers, and the safety of electrical works and the general public.

To this we would add **data access** and **security**, and **privacy**.

The table below gives an overview of how these areas are regulated in the NEM and in embedded networks, and what might be required for microgrids.

In the NEM	In embedded networks	For microgrids
Registration and licensing		
Network businesses and retailers require national and in some cases jurisdictional authorisation. Wholesale market participants must be registered with AEMO. Networks can't provide retail or generation services, except by obtaining a ring-fencing waiver from the AER (process is not streamlined).	In Vic, exempt (from licencing) networks have a reduced set of obligations, may need to be registered, are required to be members of the ombudsman scheme, and are effectively price-capped. Embedded network operators must also meet 100% of residential demand from on- or off-site renewable sources, and allow customers to contract with a retailer outside the embedded network if they wish. Outside of Vic, embedded network operators and retailers must be authorised as a specific type of market participant.	Microgrid operator by default appears to be an exempt network, exempt retailer, and maybe an exempt generator (if less than 30 MW). Not clear whether it could operate as an exempt network and also register with AEMO for wholesale market access.
Access and connection		
Networks and retailers are obliged to connect customers for both load and generation.	Networks are required to connect customers and also to allow them to contract with retailers outside the embedded/exempt network, with pass-through of DNSP network charge.	DNSPs have no explicit obligation to connect microgrids that are not established as embedded networks. Microgrid operators, if regulated as embedded networks, cannot prevent connected customers from contracting with on-grid retailers. It's not clear how embedded network arrangements would work when the microgrid is islanded, especially for extended periods.

In the NEM	In embedded networks	For microgrids
Economic regulation		
Networks heavily constrained by regulation due to privatised spatial monopoly characteristics, with expenditure, revenue, and tariff structures requiring approval in a public process. In Vic, an effective retail price cap via the VDO. Outside Vic, some discipline on retail prices via the DMO which sets a benchmark price; and more stringent price regulation in some jurisdictions.	It is assumed network capital cost is recouped through strata fees or the equivalent. Pass-through of DNSP network charges allowed. In Vic, VDO caps retail price. Outside, competition with NEM retailers assumed to discipline prices.	If the microgrid is established as a type of embedded network, the embedded network framework is probably sufficient. If not, this will need to be addressed. DNSP-led microgrids could be regulated through the usual process, but the DNSP regulatory regime has no clear provisions to account for resilience-driven investment nor local system-based charges.
Consumer protections		
Comprehensive consumer protections under the National Energy Consumer Framework, plus some additional jurisdictional protections. In Vic, the Victorian Retail Code replaces the NECF, largely mirroring it but with some variations and additional protections. Access to concessions and external dispute resolution schemes.	Broadly similar consumer protections in Vic and other states, with some adjustments reflecting smaller scale and geographic proximity.	If not regulated as embedded networks, specific regulation would be needed.
Reliability of supply		
Reliability standards for networks and generators. Incentive schemes to encourage improvements. Jurisdictional guaranteed service levels, with compensation for customers when not met.	Supply to the connection point is governed by NEM regulation and the Victorian Distribution Code. Not clear within the embedded network.	Supply to the connection point is governed by NEM regulation and the Victorian Distribution Code. Appropriate standards within the microgrid will be needed.
Network operations		
AEMO as system operator maintains system security and imposes obligations on networks accordingly. AEMO also operates the wholesale market and takes responsibility for meeting demand, including having the authority to shed load when required.	AEMO is responsible up to the parent meter. Embedded network operator has some obligations imposed by DNSP via connection agreement.	Operation of a town-sized microgrid is far more complex than a typical embedded network. Presumably connection agreement with DNSP would impose some obligations. An authorisation or accreditation scheme for operators seems useful.

In the NEM	In embedded networks	For microgrids
Safety		
Jurisdictional electrical safety rules apply, and energy safety bodies impose obligations on DNSPs and embedded network operators.		Presumably microgrids will be required to meet jurisdictional safety obligations as appropriate.
Data access and security		
Energy retailers and networks are required to give customers access to their energy data under the national energy consumer framework (NECF) and Victorian Retail Code. Within the next few years they will have more comprehensive data access obligations under the new *Consumer Data Right (*CDR) framework. Networks and retailers have obligations on data security and cyber security via a number of instruments. Those covered by the Privacy Act have additional obligations re protection of customer data.	Embedded network operators don't appear to have any data access obligations to their customers. The extent to which they have data security obligations is not clear. If embedded networks are captured under the CDR for energy, these obligations will apply to them.	Given the critical nature of an islandable microgrid and the likelihood that proactive energy management will be needed to maximise benefits, data access and security standards will be required. If the CDR is extended to microgrids, this will be taken care of.
Privacy		
Networks and retailers are covered by the Privacy Act as their turnover would be over the $3 million threshold that makes it a requirement. Any retailer small enough to be under this threshold will be covered by the Act once the CDR for energy is active, as the Privacy Act applies to all CDR participants regardless of turnover.	It's likely that many embedded networks are beneath the $3 million threshold. If embedded networks are captured under the CDR for energy, these obligations will apply to them once it is active.	Some small microgrid operators might fall under the $3 million threshold. If microgrids are captured under the CDR for energy, these obligations will apply to them once it is active.

Consumer protections

It's worth giving a bit more detail on consumer protections, to underline the scope and importance of this aspect of regulation. The importance of energy-specific consumer protections is sometimes under-estimated in policy and change processes focused on technical matters.

The Victorian and the national consumer protection frameworks cover all aspects of how energy businesses interact with their residential customers (and, to a lesser extent, small business customers). This includes areas such as:

- customer rights to access network connections and retail energy offers
- how bills are calculated and issued, and what information they should convey
- payment methods available to customers
- how retail and network prices are determined
- how retailers deal with customers in financial hardship

- how undercharging and overcharging are rectified
- obligations on notification and scheduling of planned interruptions to supply, and compensation and support during unplanned interruptions
- when and how debts may be recovered
- processes for disconnection and reconnection
- protections for vulnerable and life support customers
- internal complaints handling processes
- access to independent external dispute resolution (energy ombudsman schemes)
- authorisation of energy retailers
- reporting and compliance obligations
- concessions and emergency payment assistance
- information provision to customers

These protections are mostly delivered through the Victorian Energy Retail Code and National Energy Consumer Framework (NECF), and partly through the Victorian Distribution Code, National Energy Rules (NER), and other instruments. Those that apply to distribution businesses are actuated through the regulatory framework for DNSPs, and those that apply to retailers are actuated through the authorisation process for retailers – authorised retailers are obliged to comply as a condition of authorisation. Any energy retailer that is exempt from authorisation or network that is exempt from the standard regulatory framework is thus not bound by these requirements. This is why the exemption frameworks that govern embedded networks include conditions that subject exempt networks or retailers to delivering appropriate consumer protections – generally in line with the full suite that applies to authorised retailers and networks but adapted as appropriate to reflect the different context. Any framework that encompasses microgrids will need to contain similar provisions.

The Victorian retail regulatory framework has increasingly moved toward a consumer outcomes focus – regulating to deliver consumer outcomes rather than to define retailer behaviour. This approach is more able to adapt to changing technologies and markets, and is thus more appropriate for addressing consumer protection issue in microgrids as it is an emerging area that is still evolving.

Functional issues

These relate mainly to the technical grid services discussed in the previous section. Some aspects of a microgrid's ability to provide these services would be enabled by an appropriate regulatory framework for microgrids (e.g., licensing or authorisation of microgrid retailers and generators would determine how they can act in the wholesale market). But others need regulatory change to be fully valued. In particular:

- **Resilience and reliability:** The network regulatory framework incentivises investment to meet *reliability* standards but does not fully account for the value of investments to increase *resilience* to natural hazard events or improved reliability after a long localised outage – the costs of restoring supply after a major event can be passed through, but investment in resilience to reduce those (inevitable) costs is not valued.[22] This is not just an impediment to DNSP-led microgrids, but also makes it difficult to make a business case for a third-party one.

- **Network services:** Regulation of DNSPs still favours capital investment over non-network solutions and operational expenditure. A totex approach to revenue determinations would make it easier for networks to use innovative and non-network solutions (including microgrids providing network services) where they are cost-effective.[23] It would also provide a basis for an appropriately regulated network services market. A totex approach would involve the AER approving an overall total expenditure allowance rather than individual capex and opex allowances.

5.2 Regulatory frameworks and scenarios

The current regulatory framework does not include microgrids. It does include:

- distribution and transmission network service providers (DNSPs and TNSPs) that are part of the interconnected system and convey electricity from grid-connected generators to be sold to customers by authorised retailers;
- embedded networks: private networks connected to DNSPs' networks, with an exempt (from retail authorisation) retailer that buys electricity from authorised retailers and on-sells it to customers within the embedded network; and
- stand-alone power systems (SAPS): single sites or small networks that are not connected to the grid but have their own electricity generation and storage which they sell to customers within the SAPS. SAPS may be owned and operated by DNSPs or by other entities.

So a microgrid could be considered:

- part of a DNSP's network that has the capacity to separate from the network when desired and become a DNSP-owned SAPS;
- an Embedded Network that has the capacity to separate from the grid and operated islanded as a SAPS;
- a SAPS that has the capacity to also connect to the grid – owned and operated by either a DNSP or an independent entity; or
- a new type of entity called a *Microgrid* that is distinguished from SAPS and embedded networks.

While microgrids share numerous characteristics with embedded networks and SAPS, they also have distinctive characteristics and key differences from both. This suggests that **microgrids need to be defined in regulation**,[24] whether they will be regulated as part of the regulation of DNSPs, covered by embedded network or SAPS regulation as a special case, or regulated separately as a distinct entity. If regulated separately, a regulatory framework for microgrids could draw extensively from the existing frameworks for embedded networks and SAPS (noting that while these are both still under development, their directions are

[22] CutlerMerz (2020) *Opportunities for SAPS to enhance network resilience: Final Report*

[23] Energeia (2021) *Renew DER Optimisation (Stage II): Final Report*

[24] As recommended in numerous other papers, such as Monash University's *Reforming the regulation of local electricity supply (including microgrids)*, 2020 (noting that they suggested the term 'Local Energy Network' (rather than 'microgrid') in Monash University (2021) *Submission to Embedded Networks Review Draft Recommendations Report*, August 2021)

fairly clear) but still be distinct, and responsive to the particular circumstances, constraints and challenges that are faced by microgrids.

A good way to understand the regulatory constraints and opportunities is to examine the existing SAPS and embedded networks frameworks and then identify:

- what regulatory adjustments would be needed to enable microgrids, with their distinctive ability to operate in grid-connected and islanded mode at different times, to be included – i.e., address the existential issues;
- what constraints would limit microgrid form and functions;
- the extent to which the potential value streams are accessible without further regulatory change; and
- what further regulatory change would be needed to most fully access potential value streams.

In assessing these frameworks, we need also consider two ownership/governance options – owned by the DNSP, or independently.

This then forms the basis for proposing new regulatory frameworks for microgrids.

Using this approach, we have identified three frameworks for how microgrids might be established and regulated:

- DNSP-owned microgrid (a grid-connectable DNSP-led SAPS – based on the new DNSP-led SAPS framework);[25]
- Independent SAPS microgrid (a grid-connectable third-party SAPS – based on the proposed third-party SAPS framework);[26] and
- Independent embedded microgrid (an islandable embedded network – based on the proposed Victorian embedded networks framework[27] and/or (outside Victoria) the new national framework for embedded networks).[28]

DNSP-owned microgrid

At this point in time, the economics of transitioning part of a DNSP's network into an independently owned microgrid appear challenging, so we begin by considering a DNSP-owned approach for Donald and Tarnagulla.

Summary of existing framework

The DNSP-led SAPS framework is premised on the existence of some remote individual or groups of customers where the cost of supplying electricity is so high it would be more cost-effective to establish a SAPS than to continue to supply from the grid. In these situations, establishing a SAPS reduces the revenue requirement for the DNSP as a whole, putting downward pressure on costs for all customers. The remote customers in question don't face

[25] AEMC, *Review of the regulatory frameworks for stand-alone power systems - priority 1*, Final report, 30 May 2019

[26] AEMC, *Review of the regulatory frameworks for stand-alone power systems - priority 2*, Final report, 31 October 2019

[27] Department of Environment, Land, Water and Planning (Victoria) *Victorian Government response to the Embedded Networks Review*, July 2022

[28] AEMC, *Updating the regulatory frameworks for embedded networks*, Final report, 20 June 2019

the financial incentives themselves because 'postage stamp' pricing (sharing the varied costs to serve customers in different parts of the network evenly across the whole network) means that they face the same network charges as other customers and are being cross-subsidised.

The underlying principle of the DNSP-led SAPS framework is that customers continue to receive the same (or better) level of service, at the same price, with the same customer protections and ability to access the competitive retail market – so the DNSP does not need customer consent (though it may choose to seek it). This does not preclude cost-reflective tariffs being introduced to reallocate the same 'postage stamp' pricing differently among customers in the same area based on their load profiles.

An important consideration is that in a future with widespread distributed generation and storage, the cost to serve more remote communities might cease to be materially higher than average. In this scenario, the decreasing consumer benefit of postage stamp pricing may be outweighed by an increasing benefit of local use of system-based pricing. Transitioning from the current framework to one reflecting that scenario is a challenging prospect.

Ownership and control of generation

In the DNSP-led SAPS framework, the DNSP cannot own generation and storage assets. The DNSP must purchase generation and storage from a third party or a ring-fenced affiliate, unless they get a ring-fencing waiver if they can show there's no contestable option.

In a DNSP-owned microgrid framework, this would still be appropriate for the basic operation of the microgrid. A third-party DER owner could be a community-owned entity, which might better enable sharing value with community members.

- **Access to the wholesale market:**
  Microgrid DER is likely to have a standing exemption from being required to register with AEMO as a Market Generator (if less than 5 MW) but would need to register if it wished to trade into the wholesale market – a value stream it may wish to access. If a DNSP had a ring-fencing waiver to own DER in a microgrid, this would seem to rule out wholesale market participation – so third-party (or ring-fenced DNSP affiliate) ownership of DER would be required to capture maximum value.
- **Access to the demand response and ancillary services market:**
  Registration as a market participant would be required to access these value streams. We are not aware of any regulatory barriers to this, though again a DNSP owning microgrid DER via a ring-fencing waiver would be excluded.

Energy retail

In the DNSP-led SAPS framework, electricity is sold to consumers by NEM retailers who would purchase electricity from the SAPS generator at an administered price instead of the market generators.

In a DNSP-owned microgrid framework, this could still apply when islanded, but NEM retailers could purchase from NEM generators (which might include the community generator) and the wholesale market when grid-connected. This is probably still consistent with offering microgrid customers standard retail tariffs.

- **Optimising use of DER and network assets within the microgrid:**
  Maximum value from this is likely when the retailing and generation functions are well-coordinated. This is most **likely when one retailer has majority coverage** within the microgrid and works closely with the DER operator(s) for community benefit, or a vertically integrated DER owner/retailer. It would also be **assisted by network charges that are cost-reflective and local within the microgrid**. This would be a significant departure from the DNSP-led SAPS framework. In particular, if a microgrid was to use local use of system charges to increase value from local generation and control, it would be inconsistent to subsidise network costs for access to grid energy – which is a fundamental rationale for the DNSP-led SAPS framework in the first place.
- **Access to retail competition:**
  This is retained through access to NEM retailers but as noted above - obscuring local price signals for generation and network usage could limit value from optimising energy resources within the microgrid. A single community-based retailer with a capped price, based on the Victorian Default Offer (VDO), could meet the same objectives of retail competition but again is a significant departure from the DNSP-led SAPS framework. However, a community-based retailer competing with NEM retailers but making full use of local area tariffs that reflect local energy costs could capture some value (assuming costs are lower than average NEM wholesale costs), and a variation in regulation could allow NEM retailers to offer tariffs specific to the microgrid and the local cost stack.

Network services

In the DNSP-led SAPS framework, the SAPS is disconnected from the rest of the network, so cannot offer network services to the grid. Network services within a SAPS, if required are integral to the operation and control of the SAPS by the DNSP or through contractual arrangements with DER owners. Because current contenders for DNSP-led SAPS are single customers or very small groups, network services aren't a useful concept.

In a DNSP-owned microgrid framework, the relationship between the DNSP and third-party owners of DER will be contractually-determined. Network services within the microgrid could be encompassed in the terms of a connection agreement. While contracts could also encompass delivery of network services outside the microgrid, it seems more transparent provide them through a regulated network services market. As noted earlier, this would presuppose broader regulatory changes to more clearly value non-network solutions to network operational, maintenance and upgrade requirements.

- **Cost-reflective network tariffs:** these are an avenue for managing network issues within a microgrid, and having specific network tariffs within a microgrid would be a variation to the DNSP-led SAPS framework and a barrier to NEM retailers offering standard tariffs. It may also require variation of the Victorian obligations for DNSPs to allow opt-out of cost-reflective network tariffs and retailers to offer a flat tariff (though retailers have other opportunities to manage variable network pricing than passing it on directly to customers). Additionally, as noted above, cost-reflective

local pricing within a microgrid seems inconsistent with subsidised grid supply through postage stamp pricing.
- **Demand management programs:** Alternatively (or additionally) DNSPs could procure demand response directly from customers to manage network congestion and constraints both within and beyond the microgrid. However, it seems likely that more targeted and consistent responses would result from commercial incentives or arrangements with DER operators and retailers.

In summary

Possible variations on the DNSP-led SAPS framework to form a DNSP-owned microgrid framework could be:

- Connection agreement requires DER owner/operator to meet community demand but allows registration as a Market Generator and Market Ancillary Service Provider, and activity in those markets, in doing so.
- Administered price applies only when islanded.
- Removal of right to opt-out from cost-reflective network tariffs - along with requiring local network tariffs and possibly a more cost-reflective tariff at the grid connection. This would mean a microgrid is only viable if there is a cost reduction from local use of generation and network that offsets cost increase from exclusion from postage stamp pricing.
- Possibly, allowance for a single microgrid retailer (or vertically integrated microgrid gentailer) that meets a community benefit test and is subject to a price cap.

These would probably be in a context of the microgrid meeting an economic test that demonstrates there's an overall community benefit – keeping in mind that the DNSP-led SAPS framework is itself premised on an overall benefit to the DNSP's customers.

Independent SAPS microgrid

The AEMC's review of the SAPS framework determined that third-party owned SAPS could be split into three categories:

1. **Category 1** would comprise very large microgrids that warrant regulatory determinations by the AER and could support generation and retail competition. These could thus be regulated in equivalent manner as standard supply.
2. **Category 2** microgrids would range from those connecting more than a handful of customers to those supplying smaller towns. They would be too small to justify regulatory determinations, would probably be vertically integrated and unable to support generation and retail competition. Thus they could be regulated by jurisdictions to impose the necessary consumer protections, safety standards and operational obligations on the operators of these systems.
3. **Category 3** would encompass very small microgrids with a handful of customers. These could be regulated by jurisdictions to impose minimum consumer protections, such as billing requirements, as well as energy-specific safety requirements, basic metering requirements and technical standards.

We are assuming that the microgrids being considered for Donald and Tarnagulla, and other potential microgrids for which this project is relevant, fit within Category 2.

In this section we will examine regulatory issues for third-party SAPS together with those for embedded network. This is partly because we consider that Category 2 third-party SAPS and Embedded Networks are essentially the same except for the main distinguishing feature of microgrids – the ability to operate as an embedded network or a SAPS by connecting or disconnecting form the grid; and partly because the most appropriate framework for jurisdictions to base their regulation of third-party SAPS on is the embedded networks framework. Anything distinct to SAPS will be noted.

Independent embedded network microgrid

Embedded electricity networks are "privately owned and managed electricity networks that … supply all premises within a specific area or building… [and] buy electricity in bulk and then on-sell it to customers inside their network."[29] While they are typically apartment buildings, caravan parks, shopping centres or retirement communities, they are similar to microgrids in that they are a distinct network with one connection point to the wider grid. If you add some storage and generation and make them islandable, then embedded networks could be microgrids.

Embedded networks typically (and third-party SAPS can be expected to) have a vertically integrated electricity supplier, specific tariffs based on local costs, and management of load within the network (and for embedded networks, at the connection point) – qualities that seem suitable for microgrids. Noting of course that managing a town-sized microgrid within operating parameters and maintaining assets is likely to be more complex and specialised than managing an embedded network in a large apartment building. Nonetheless, the existing frameworks for embedded networks (and third-party SAPS) cannot fully encompass microgrids without regulatory changes that would need to be specific to microgrids to avoid undermining the policy intent for embedded networks and SAPS. A clear definition of microgrids would be required as part of this approach, detailed enough to distinguish it from an embedded network with some DER installed.

The Victorian embedded networks framework

The new Victorian regulatory framework for embedded networks[30] – still being implemented – has a number of aspects that would be appropriate for microgrids, and others that would not be.

Renewable energy proportion

The new Victorian framework will allow new embedded networks if 100% of the electricity supplied to customers comes from on-site or off-site renewable sources. This was a change

[29] https://www.consumer.vic.gov.au/products-and-services/energy-products-and-services/embedded-electricity-networks

[30] Department of Environment, Land, Water and Planning (Victoria) *Victorian Government response to the Embedded Networks Review*, July 2022

to the original intent to require 50% from on-site sources due to the recognition that for many large high-rise apartment blocks there was limited capacity for on-site generation.

- **In microgrids:** because of the requirement for diesel generation in the Donald and Tarnagulla microgrids (and likely others), they could not meet this requirement.[31] A threshold – possibly 50% as originally proposed in the embedded networks review, but more modelling might be required to arrive at a practicable threshold – for on-site renewable generation may be suitable. In the future, when battery prices have come down sufficiently to make them more cost-effective than diesel gensets, this could be realigned with the embedded networks framework.

Retail authorisations and customer protections

The new Victorian framework will have a licensing framework for Local Energy Services – embedded network providers and embedded network retailers – that requires them to meet similar legal obligations to other energy distributors and retailers (including access to external dispute resolution via the Energy and Water Ombudsman), but scaled and defined as appropriate for their smaller size and limited scope. These obligations include delivering equivalent consumer protections to on-market customers as delivered by the Victorian Retail Code and other instruments.[32]

- **In microgrids:** this would ensure microgrid customers have appropriate consumer protections and service standards.

Retail pricing and competition

The new Victorian framework (and the new national framework) requires embedded networks to give customers access to market retail offers from outside the embedded network, to ensure price competitiveness. The Victorian framework caps embedded network retail pricing at the level of the Victorian Default Offer (VDO), and the new national framework permits the Australian Energy Regulator (AER) to set a price cap (lower than or equal to the standing offer of the local area retailer) in legacy embedded networks that cannot give access to NEM retailers.

- **In microgrids:** the viability of an independent microgrid is likely to depend on the economies inherent in coordinating all supply and demand within its boundaries, and optimising use of local resources with grid resources (the techno-economic analysis we discussed in section 4.3 *The value of regulatory reform* (on page 26 above) suggests this). A vertically integrated (generation–distribution–retail) local energy supplier may be the most effective way to do this – and certainly is implied in some of the literature.[33] To ensure appropriate customer protections and support

[31] Noting that the cost-effectiveness of microgrids without diesel generators may be improved with access to sufficient external value streams – though diesel generation as a backup may still be required in the medium term.

[32] The new national framework has similar requirements for registered Embedded Network Service Providers and authorised off-market retailers (AEMC, *Updating the regulatory frameworks for embedded networks*, Final report, 20 June 2019)

[33] E.g. Monash University MEMO report *Microgrid Development in Victoria: Policy Opportunities and Future Regulation*, June 2021, AEMC, *Review of the regulatory frameworks for stand-alone power systems - priority 2*, Final report, 31 October 2019

the viability of independent microgrids, the Monash Microgrid Project recommended customers be required to give informed consent to opt-in to a microgrid's local energy supplier, but that the agreement could include an explicit waiver of their right to subsequently switch to a conventional retailer for a defined period.[34] In conjunction with the retention of other consumer protections in the embedded network framework (including the VDO price cap), this probably does not materially impact microgrid customer protections relative to conventional customers. We are undecided as to whether having customers waive their right to switch to a NEM retailer would be required for an embedded network microgrid. However, if a NEM retailer had customers in an embedded network microgrid it would need to purchase electricity from the microgrid generator when the microgrid is islanded.

Network tariffs

The existing embedded network frameworks in Victoria and nationally do not permit embedded network operators to charge network tariffs for the embedded network itself.[35] (They are permitted to pass through network charges from the DNSP to the embedded network as a whole.) This is based on the assumption that cabling and other equipment needed to enable and operate the internal network is part of the build cost and included in purchase prices of apartments/units etc.

- **In microgrids:** the network in a town-sized microgrid is fundamentally different to an apartment block, and likely to be larger and more complex than in a retirement community or caravan park. Additionally, optimal management of the microgrid is likely to be assisted by local use of system-based pricing that is cost reflective. Allowing microgrids to include internal network charges in customer pricing is probably conducive to managing overall pricing and operation. The imposition of a price cap such as the VDO will help manage customer price outcomes. Network pricing rules specific to microgrids would need to be developed by the relevant rule maker/regulator (Essential Services Commission in Victoria, AEMC and AER nationally).

Reliability and service standards

Existing regulation of DNSPs includes standards for reliability and service provision including things like targets for minimising outages and rules for communicating about both planned and unplanned outages to customers. Attached to this is an obligation to pay compensation to customers when standards are not met, and some obligations on DNSPs to assist customers with life support equipment or other critical energy needs.

- **In microgrids:** there are two aspects of this to address for microgrids based on an embedded networks framework. One is the extent to which microgrid operators should convey to microgrid participants information from the DNSP about outages and other matters that impact grid electricity supply to the microgrid. This will

[34] Monash University MEMO report *Microgrid Development in Victoria: Policy Opportunities and Future Regulation*, June 2021

[35] With limited exceptions for large commercial and industrial customers.

depend on the microgrid's capacity to island and any expectation of the community to be able to access grid electricity at any time. The other is the imposition of reliability and service standards directly on microgrid operators with respect to energy supply – from whatever source – within the microgrid. This has been recognised as a shortcoming of embedded network frameworks, and is probably even more necessary for microgrids given the extent of control microgrid operators are likely to have over energy flows within the community.

Connection policies

Existing regulation requires DNSPs to connect embedded networks on a standard connection agreement. DNSPs can, but are not required to, offer connection to a non-registered embedded generator, nor to a class of customer, for which no model standing offer exists.[36]

- **For microgrids:** the Monash Microgrid project recommended that "a *standard connection agreement for local electricity supply systems* should be developed with Victorian distributors and available as an entitlement to microgrid operators and users as a distribution licence condition"[37], and we agree this is likely to be necessary.

Overview of regulatory issues for microgrids for different frameworks

This table compares some key aspects of service provision across different regulatory frameworks. Each pair of rows compares what is currently the case in existing frameworks, with what might be the case in microgrid frameworks based on the existing frameworks.

[36] Noted in Monash University *Submission to DELWP Embedded Networks Review Issues Paper*, 26th February, 2021

[37] Monash University *Submission to DELWP Embedded Networks Review Issues Paper*, 26th February, 2021: p. 8

Framework	Ownership of DER	Energy Retail	Access to wholesale market	Providing network services	Optimising use of DER within MG
DNSP-led SAPS	DNSP must purchase generation and storage from a third party.	NEM retailers purchase from SAPS generator at administered price.	N/A as not connected.	N/A as not connected. (DER operator might provide network services within SAPS, in terms of contract with DNSP?)	Up to DER operator in collaboration with retailers and/or incentives to customers. May also be determined by contract with DNSP.
DNSP-owned MG	DNSP must purchase generation and storage from a third party.	NEM retailers purchase from SAPS generator at administered price when islanded, and from NEM generators or MG DER operator when grid-connected. *Potential for a competitive or monopoly MG community retailer?*	NEM retailers have access. DER operator (and community retailer) could have access if registered.	Could be defined in terms of contract with DNSP. Assisted by regulatory changes to value non-network solutions more clearly. Perhaps optimised by a regulated network services market.	Improved by coordination between DER operator and retailer(s). Assisted by network charges that are cost-reflective and local within the microgrid.
Third-party SAPS	Vertically integrated, state regulated.	Vertically integrated, state regulated.	N/A as not connected.	N/A as vertically integrated	Vertically integrated energy service is already incentivised.
Third-party MG	Vertically integrated, state regulated.	Vertically integrated, state regulated. Also purchase from NEM retailers or directly from wholesale market if registered.	Yes if registered.	Via connection agreement or network services market. Assisted by regulatory changes to value non-network solutions more clearly.	Vertically integrated energy service is already incentivised.
Embedded network	Vertically integrated, state regulated, but also may give access to NEM retailers	Purchase from NEM retailer	No	Via connection agreement	Vertically integrated energy service is already incentivised – but limited influence over NEM customers.
Embedded MG	Vertically integrated, state regulated, but also may give access to NEM retailers	From own DER, also from NEM retailer(s) or directly from wholesale market if registered.	Yes if registered.	Via connection agreement or network services market. Assisted by regulatory changes to value non-network solutions more clearly.	Vertically integrated energy service is already incentivised – but limited influence over NEM customers.

5.3 Other issues for microgrids

Capacity building, ownership, and governance

In developing regulatory frameworks for microgrids, community engagement and models for risk mitigation and community benefit capture must be considered.

Microgrids are likely to be primarily community-driven, bottom-up initiatives that then must engage with the complex institutional electricity system to be realised. This project has already demonstrated how easily the community can become alienated from the institutional and industrial stakeholders in a major energy project.

We recognise in this study the work undertaken by community members in Donald and Tarnagulla to develop local generation capacity and advocate for addressing barriers to capturing local benefits. We also recognise that such local efforts rely upon a range of skills including energy system literacy, techno-economic analysis, institutional engagement, advocacy, and community engagement. This complex combination of skills is currently not present in many communities, nor are these skills evenly distributed within communities.

Microgrid projects can be an opportunity to bring productive debate and visioning to communities; but to do so requires significant capacity building. Groups such as the Community Power Agency (CPA) provide a range of resources to do so. But more investment is needed in building capacity for communities to participate in these debates.

There are a range of practical issues around what models of governance best facilitate delivering benefits for the community, and how these might interact with the existing regulatory requirements of the NEM. While not within the scope of this project, we can see that communities require significant techno-economic advice to realise their ambitions. Commercial models for ownership and governance need to align with community values and visions. There is more research needed to understand how government can assist in mitigating risk, facilitate benefit-sharing within communities, and help to scale community energy models.

Local microgrids require new models of ownership and governance to be trialled and developed. There is an urgent need for applied research to explore community benefit tests, community-ownership models, accreditation of community energy providers, and the application of consumer protections.

Some people in the Donald and Tarnagulla communities looked to local governments to be a key enabling institution for local microgrids; but the capacity and resources of local government to undertake this role varies significantly across Victoria. There is significant work to be done here.

The new State Electricity Commission (SEC) was also seen by some as a potential community-benefit focused microgrid operator. Given the clear benefits a not-for-profit monopolistic vertically integrated energy business could deliver for microgrid communities, the potential of this is worth further investigation.

Operator of last resort

The NEM has a 'Retailer of Last Resort' (RoLR) scheme to protect customers from a retailer failure. This assigns a default retailer to customers of a retailer that collapses or exits the market.

The AEMC SAPS review recommended an Operator of Last Resort (OoLR) be set up by jurisdictions to assign a network operator to take over a stand-alone power system if a SAPS provider collapses and the SAPS provider has not itself assigned an alternative provider.

The new Victorian embedded networks framework will give the ESC powers to appoint an alternative provider if an embedded network operator can no longer sell or supply electricity to its customers.

An embedded network microgrid framework will need the same or an equivalent scheme.

Establishment costs

A new community connecting to a DNSP's network as a microgrid would presumably recover capital costs either solely through initial purchase prices for land and buildings in the community, or some combination of that and ongoing network charges, depending on the rules governing network charges in an embedded microgrid (noted above).

For an existing township or other community transitioning from being part of a DNSP's network to becoming an independently-owned microgrid, we see two options:

- a contractual agreement with the DNSP covering usage, management, maintenance etc. of their network assets within the microgrid. Costs of this would need to be recouped through network charges within the microgrid;
- sale of network assets to the microgrid operator, which is then required to operate and maintain to meet relevant performance and safety standards. Costs of this would need to be recouped through network charges within the microgrid.

It seems likely that the expertise to operate and maintain distribution assets is limited outside DNSPs – with the obvious exception of ring-fenced affiliates of DNSPs.

In all cases, the DNSP has a privileged position in determining the value of assets to be sold or leased, and services to be contracted, so some regulatory oversight is likely to be necessary for the required transparency and to enable the potential of third-party microgrids to be realised.

6 Recommendations to regulators

Our view is that the potential value of coordinated management of demand and supply within the microgrid is so high that regulatory frameworks supporting maximum coordination of generation, network management, and energy purchasing and retailing are desirable, if practicable.

We are not convinced that regulatory change at the level of a rule change is required. Rather, a framework review to determine how best to enable microgrids to be appropriately governed and regulated, and reach their full potential. It seems possible that microgrids could be encompassed by the SAPS or embedded networks frameworks, with appropriate definitions and delineations, and a consumer outcomes-focused approach designed to deliver consumer and community benefits and avoid perverse outcomes.

6.1 Recommendations

A. A clear regulatory definition of microgrids is needed.

B. Regulatory reforms for distribution networks are required to properly value what microgrids can offer.

C. A DNSP-owned microgrid framework is needed, based on the DNSP-led SAPS framework but allowing passthrough of price benefits from optimisation of generation, storage and demand within the microgrid and access to system markets.

D. An embedded microgrid framework is needed, based on the embedded networks framework but allowing local use of system network charges, interactions with system services and markets, and an operator of last resort scheme.

E. A process to examine energy consumer protections and determine:

   i. how best to impose consumer protection obligations on the relevant parties for different types of microgrids, from a consumer outcomes focused perspective; and

   ii. which specific consumer protections might need to be varied to be applicable in a microgrid with its own energy provider, or to avoid perverse outcomes (in the same way that some obligations are varied for embedded network retailers e.g. publication of offers).

F. A framework for accrediting and overseeing community-benefit energy providers in microgrids may be useful, in which specific consumer protections and other regulatory obligations might be varied.

G. A transition plan is needed to enable predictable regulatory change towards more cost-reflective network pricing when distributed generation, storage, and demand response are more ubiquitous and widely distributed.

6.2 Further work

Some of the above proposals have consequences for the current equity and customer protection principles embedded in retail and network regulation. These regulatory proposals must be considered and debated in terms of evolving distributive equity principles and frameworks, and emerging models of governance and community participation, as we move into the beginnings of a just transition towards more decentralised energy resources. This is priority work that lays the foundation for the reforms that we are proposing but remains outside the scope of our terms of reference. We have identified two potential future projects that would help develop these necessary reforms:

- Developing ownership and governance models for microgrids that realise community visions for shared ownership and benefit-sharing, and to mitigate risks. Community engagement and capacity building should be understood as core issues and explored in parallel with regulatory reform. This work would inform recommendation F above.
- Reviewing the distributive equity principles and frameworks inherent in regulation of DNSPs and exploring how to maintain equitable cost-sharing as the reallocation of network capacity to users changes over time in the move toward more decentralised energy resources (particularly connected to low-voltage networks). This is an aspect of the just transition to a net-zero energy system that, to our knowledge, has not been widely explored. This work would inform recommendation G above.

7 Appendices

7.1 Appendix 1: Key references

Monash Microgrid Project

- See https://www.monash.edu/net-zero-initiative/publications
- In particular:
    - For good overview of Vic regulatory issues: *Reforming the regulation of local electricity supply (including microgrids) – January 2020*; and *Microgrid Development in Victoria: Policy Opportunities and Future Regulation – June 2021*
    - For discussion of how a microgrid is and is not like an embedded network: *Submission to DELWP Embedded Networks Review Issues Paper – 26th February, 2021*

CutlerMerz, Energy Networks Australia and the Total Environment Centre

- On regulatory impediments to resilience–related network investments: CutlerMerz, ENA, & TEC (2020a) *Opportunities for SAPS to enhance network resilience: Final Report October 2020* (https://www.energynetworks.com.au/resources/reports/2020-reports-and-publications/opportunities-for-saps-to-enhance-network-resilience/)
- On the benefits of a requirement for networks to invest in resilience measures: CutlerMerz, ENA, & TEC (2020b) Network Resilience – Potential benefits of a requirement to provide for resilience: Final report 23 December 2020 (https://d3n8a8pro7vhmx.cloudfront.net/boomerangalliance/pages/4029/attachments/original/1611269543/CMPJ0391_-_TEC_Network_Resilience_v4.1.pdf)

Australian Energy Market Commission

- AEMC, *Review of the regulatory frameworks for stand-alone power systems - priority 1*, Final report, 30 May 2019
- AEMC, *Review of the regulatory frameworks for stand-alone power systems - priority 2*, Final report, 31 October 2019
- AEMC, *Updating the regulatory frameworks for embedded networks*, Final report, 20 June 2019

Victorian Government

- Department of Environment, Land, Water and Planning (Victoria) *Victorian Government response to the Embedded Networks Review*, July 2022

7.2 Appendix 2: *The value of regulatory reform* full report

Title:	**Project 11 - Modelling**
Synopsis:	This document summarises the studies conducted and the results obtained for Project 49.11
Document ID:	Project11_Modelling_Report_vf.docx
Date:	17th of April, 2023
Prepared For:	Centre for New Energy Technologies (C4NET)

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Executive Summary

The microgrid operational model developed in Project 8 “Economic and Risk Assessment” has been deployed to support the discussion on regulatory frameworks and regulatory developments. The main objective is to quantify the impact of possible regulatory developments, and in turn, identify the value drivers for microgrids. The framework details are thoroughly discussed in the Project 8 report [1] and the main attributes of the microgrid operational model are the following:

- The inclusion of the MV network of each town and relevant operational constraints that impact the value the microgrid can provide to each town.
- The inclusion of different system-level and local value streams using sufficient time granularity that allows to capture extreme conditions where microgrids can provide significant value
- It considers network investment cost recovery by including the network use of services (NUoS) charges that customers are subject to. Therefore, the underlying assumption is that the DNSP or a different equivalent entity owns the network assets in the microgrid and is in charge of the operation and maintenance of those assets.

The techno-economic framework was used to study the techno-economic impact of different scenarios representing various regulatory options on the following topics:

- Operation of centralized or privately-owned DER
- Provision of energy services to the community
- Co-optimisation of energy and frequency control ancillary services (FCAS)
- Application of network tariffs
- Supply local energy demand during extreme weather events
- Provision of network services to the upstream grid

On the operation of centralized or privately-owned DER, the proposed study considered a single centralized battery energy storage system (BESS) and distributed privately-owned BESS with equal aggregate installed capacity and compared their ability to provide retail tariff energy arbitrage to reduce the total energy costs of the community:

- The results highlight that centralized DER, operated in coordination with the whole community, as opposed to privately-owned DER, operated for the benefit of the individual customer results in lower energy costs and has potential to provide further value to the community. Therefore, the study of community frameworks is highly relevant in the transition towards low-carbon power system aligned with (National Electricity Objectives) NEO principles.
- It must be noted that the proposed study only considers the MV network, and customers are aggregated at MV/LV transformer level. Further accuracy on the implications of installing central DER as opposed to distributed and privately-owned DER can be achieved by including in the modelling the LV network and each specific customer. Nevertheless, complete individual smart meter customer data is not available.

On the provision of energy services to the community, the proposed study considered different scenarios in which a centralized BESS can provide energy arbitrage to the community.

- The main finding of this analysis is that there is significant value in the coordination of the centralized DER with the remaining resources in the community (energy demand and privately-owned DER). The results show that frameworks that enable the centralized DER to provide arbitrage to the community energy needs as a whole can unlock further benefits for the community when compared to centralized DER independent market operation.
- Nevertheless, the value of coordination seems to be highlighted with higher penetration of privately-owned DER in the community. In communities with lower shares of privately-owned DER, further benefits might arise from centralized DER independent market operation. Further studies need to be performed to provide relevant figures of which level of privately-owned DER ensures the value of coordination is significant.
- While the community being subject to wholesale market prices presents opportunities to reduce costs it also entails risks, as it might be subject to high price periods. Therefore further analysis is required to provide better estimates on potential risks and benefits from being subject to wholesale market prices. The comparison between Donald and Tarnagulla, seems to display that larger communities might result in further value from facing wholesale market prices.

- It must be noted that being subject to wholesale market prices does not entail end-customers are subject to those prices. A third-party taking the role of community or microgrid operator can offer a competitive retail rate for customers in the community, with its profits arising from the difference between the revenues from the retail rate offered to customers, and the community net position from wholesale market participation. The key aspect that requires a more detailed analysis is to understand if the potential value of the community participating in the wholesale market as opposed to being subject to a community retail rate allows for the third-party to accrue sufficient profits while proposing a competitive retail rate (lower retail rate than the NEM retailers) for the community customers.

On the co-optimisation of energy and frequency control ancillary services (FCAS) the proposed study considered different scenarios in which a centralized BESS can provide energy arbitrage to the community while participating in FCAS market.

- Enabling centralized DER to co-optimize the provision of different services it is key to provide more value to the community, resulting in a significant improvement in its economic position, as opposed to only providing energy services.
- The different frameworks by which centralized DER can provide energy services allow for co-optimization of FCAS market participation. Therefore, FCAS participation is not a determining factor to decide which energy service framework is more appropriate. In this sense the findings remain consistent, displaying significant value in the centralized DER being coordinated with the community demand and privately-owned DER to provide energy services.
- With the current levels of privately-owned DER in both communities (and negligible privately-owned BESS installed) establishing a virtual power plant (VPP) in which the privately-owned DER can be coordinated to provide FCAS results in limited additional value. Further studies need to be performed with higher privately-owned DER penetration, including the existence of BESS, to understand the value of establishing a VPP.

On the application of network tariffs two sub-studies were performed. In the first study different existing network tariffs were applied to customer-level and community-level, also studying a novel community battery tariff, resulting in the following insights:

- When the centralized BESS is subject to the proposed community battery (CB) Trial Tariff, BESS imports are heavily charged during the evening (4:00 to 9:00 PM). The results display the CB Trial Tariff is useful to avoid increased peak demand conditions as a result of the BESS dispatch. Nevertheless, the CB Trial tariff does not improve the community performance, and does not necessarily incentivize the centralized BESS to reduce evening peak demand conditions arising from high demand in the community, since the incentives on exports in the CB Trial Tariff are relatively low during the evening peak. Finally, high demand periods outside the evening are not controlled and can be exacerbated by the BESS as imports are not charged during other periods.
- If the BESS is subject to wholesale market prices, the HV customer tariff prices on community energy imports are orders of magnitude lower than wholesale market prices. Therefore, these are ineffective in shifting the BESS dispatch, which prioritizes wholesale market arbitrage. However, it effectively reduces the total community peak demand throughout all instances, not only during the evening peak
- In terms of regulatory development, there is significant potential on tariffs at community-level, which the centralized DER can respond to. A possible avenue is to design a new community network tariff to be applied at the interface of the community with the upstream grid, while being reflective of the costs of the MV and LV network. Another avenue is to use existing HV customer tariffs while implementing a LUoS inside the community, which can ensure the MV and LV network costs are recovered.

On the application of network tariffs two sub-studies were performed. The second study focuses on the different components in existing network tariffs: usage and capacity/peak demand. These are applied at community-level.

- Currently network charges on usage are applied only for imports. Therefore, with a network tariff at the community interface with a significant usage charge (equivalent to the current Residential ToU tariff) the community operation effectively increases its economic “self-sufficiency”. That is, given there are additional charges when importing energy from the upstream grid, but there are no additional benefits when exporting, the BESS is operated to increase the use of local generation. Therefore during more instances throughout the day, the net exchange of the community with the upstream grid is null. If an underlying objective of establishing energy communities is to promote self-sufficiency, usage network charges at community-level can incentivize this behaviour.

- Including network tariffs at community-level and having centralized DER respond to them results in increased energy costs for the community. Among the different options available, network tariffs charging usage at community-level allow the centralized DER to provide network benefits (cost-efficient use of networks) while showing less impact on increased energy costs for the community.
- Community peak demand charges have a material impact in the BESS dispatch. The BESS co-optimizes the peak demand reduction with wholesale market arbitrage. In turn, the community peak demand is reduced during the different critical instances throughout a day when compared to the remaining scenarios.
- Network tariffs can be comprised of two components i.e., usage and capacity/peak demand. Each charge has a distinct impact on the community operation when applied at community-level. Operationally, when having both components in the network tariff the community imports and exports are similar to a case where only usage is charged, except during the peak demand conditions, in which the BESS is dispatched to reduce those critical peak conditions.

On the supply local energy demand during extreme weather events, previous work performed in Project 8 is used, quantifying the techno-economic benefits of having centralized DER in place to reduce the impact of these events in the community:

- Increased reliability from investing on the centralized DER can provide significant value to the community. Therefore, it is highly relevant that this value stream is included, with the appropriate framework that enable DER to have an emergency response to supply the local demand during these events.

On the provision of network services to the upstream grid, both congestion management services and voltage management services were studied. As there is no market or general arrangement for centralized DER to provide network services, significant assumptions were required. For congestion management, a demand response (DR) service was generated using data from other Victorian DNSPs in terms of payments and frequency of DR event. For voltage management, United Kingdom prices on reactive power support were considered ($5.6/MVArh). It assumed that reactive prices will be non-zero and negative during high solar generation to promote reactive power absorption and reduce voltage rise, and non-zero and positive during evening peak demand conditions to promote reactive power injection to reduce voltage drop issues. It must be noted the purpose of these studies is not to propose a framework to value network services, but rather demonstrate the ability of the community to provide these services, demonstrate there is potential economic value and initiate the discussions on how to value network services. Given the above, the main insights drawn are:

- The centralized DER can be operated to provide valuable network services (i.e., congestion and voltage management) to the upstream grid. Additionally, if these network services are required, significant revenues can be accrued by the community, improving its net position.
- Further studies are required to better understand what network services might be required in feeder in which Donald and Tarnagulla are connected. This will allow to provide more accurate estimates of economic impact for the community. Nevertheless, the potential for a community with centralized DER to provide upstream network services should not be disregarded. First, there is a significant potential technical benefit to manage network constraints. Second, when these benefits are considered within DNSP planning methodologies, it can potentially result in avoided network reinforcement.

Table of Contents

1 Scenarios

The following scenarios for regulatory development are generated to quantify the value of regulatory developments in the context of microgrid and energy community frameworks.

1.1 Motivation for energy communities and microgrids

The objective of this study is to understand if the resulting operation of distributed, privately-owned DER is more economically efficient than central, community-owned DER. To this end the following scenarios are generated:

- Distributed DER
- Centralized DER

1.2 Access to markets and services

1.2.1 Only energy arbitrage services

The objective of this study is to understand the implications of different frameworks for centralized DER to provide energy arbitrage services to the community, quantifying the community energy costs in the following scenarios

- Community retail rate
- Community wholesale (WS) market
- BESS front-of-the meter (FOM) wholesale (WS) market + Customer retail rate

1.2.2 Co-optimization of energy and FCAS services

The objective of this study is to understand the implications of different frameworks for centralized DER to provide energy arbitrage services to the community while co-optimizing FCAS participation, quantifying the community net position in the following scenarios

Community retail rate
- Community wholesale (WS) market
- BESS front-of-the meter (FOM) market
- Virtual Power Plant (VPP)

1.3 Network tariffs

The objective of this study is to understand the implications of different frameworks for community network tariffs, and how it impacts the techno-economic operation of the community in the following scenarios:

- Customer-level network tariffs:
- Customer-level network tariff and Community battery trial tariff
- Customer-level network tariff applied to the community interface
- Community network tariff as a HV customer

1.4 Increased Reliability

The study of reliability corresponds to the analysis performed in Project 8, and its results are included in this report for completeness. Nevertheless, no additional modelling was performed.

1.5 Provision of network services to upstream grid

Two scenarios are generated for each of the network services (congestion and voltage management) to the upstream grid)

- No provision of the service (i.e., congestion or voltage)
- Provision of the service (i.e., congestion or voltage)

2 Techno-economic framework inputs

2.1 Community data

The proposed analysis is conducted over a typical summer week, a typical winter week, and a typical mid-season week, from the available smart meter data retrieved in Project 7, which dates from 15th of January 2020 to 31st of December 2020. The selected weeks are the following:

- Typical summer week: 14th to 20th of December 2020
- Typical winter week: 1st to 7th of August 2020
- Typical mid-season week: 1st to 7th of April 2020

2.1.1 Donald

The MV network of Donald has a voltage level of 22kV and its topology is displayed in Figure 1. Voltages in the MV network are bounded to remain in the interval of ±5% of the nominal voltage.

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

Table 1. Donald demand, PV generation and battery storage capacity installed

Annual Energy Consumption (GWh)	Peak Demand (MW)	Annual PV Generation (GWh)	Peak PV Generation (MW)	Battery Storage Installed (MWh)
12.45	3.67	1.28	0.78	0

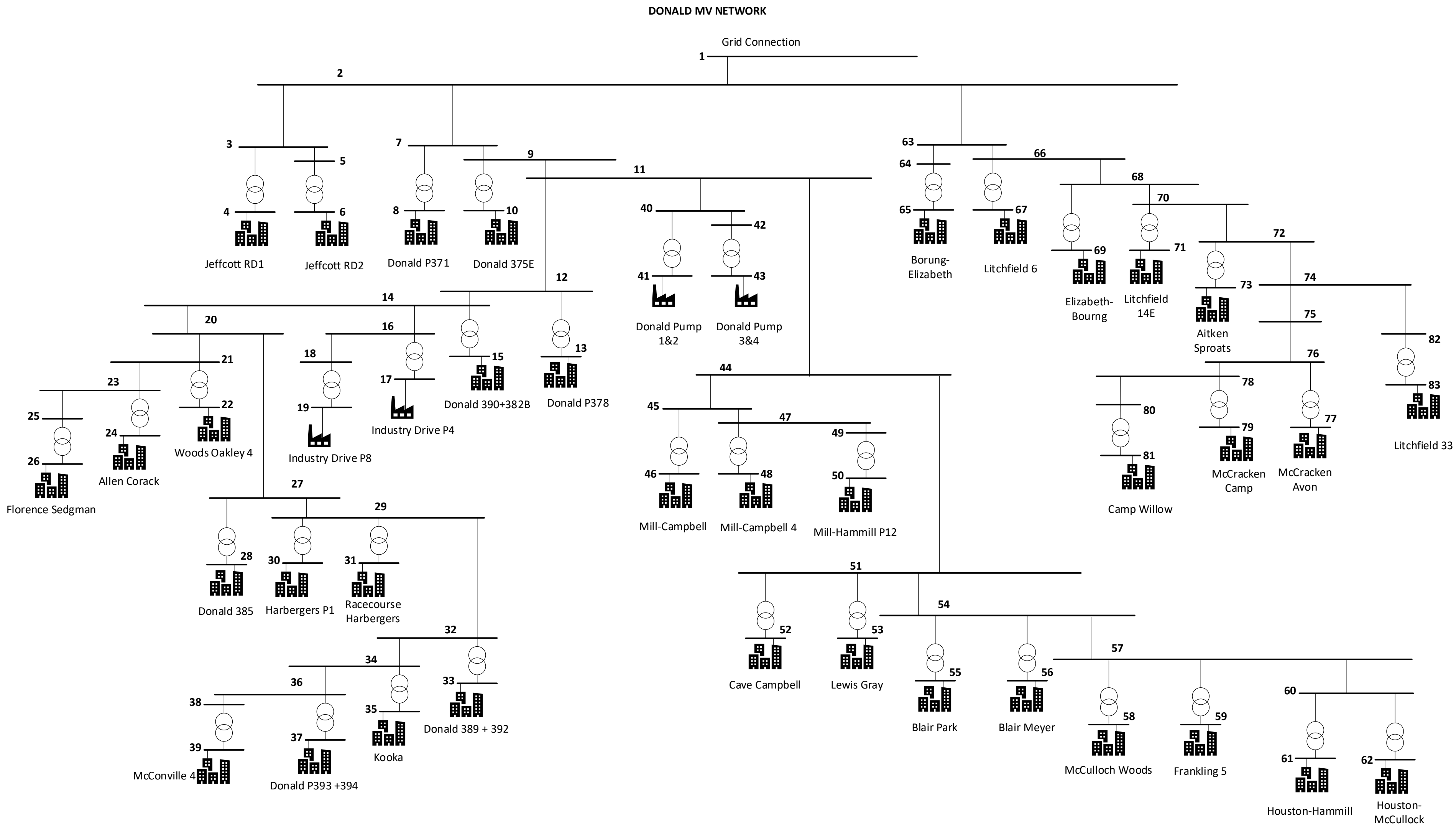

Figure 1. Donald MV network included in the microgrid investment and operational model

2.1.2 Tarnagulla

The MV network of Tarnagulla has a voltage level of 22kV and its topology is displayed in Figure 2. Voltages in the MV network are bounded to remain in the interval of ±5% of the nominal voltage.

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

Table 2. Tarnagulla demand, PV generation and battery storage capacity installed

Annual Energy Consumption (GWh)	Peak Demand (MW)	Annual PV Generation (GWh)	Peak PV Generation (MW)	Battery Storage Installed (MWh)
1.3	0.41	0.26	0.185	0

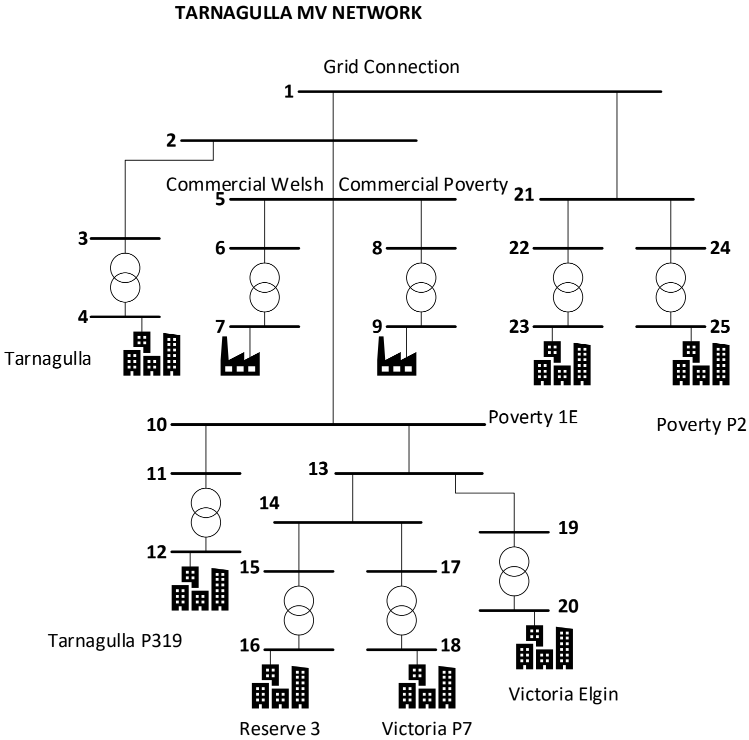

Figure 2. Tarnagulla MV network included in the microgrid operational model

2.2 Market Data

To analyse the microgrid optimal operation under different regulatory frameworks, publicly available historical wholesale energy market and frequency control ancillary services (FCAS) prices are retrieved. In the techno-economic analysis in Project 8 it was found that market prices are a key parameter that affects the value the microgrid can provide to the community. Higher and volatile wholesale energy market and high FCAS prices result in the microgrid accruing more revenues from accessing these markets. Given the historical market data from 2010 to 2022 presented in Figure 3 and Figure 4, the year 2017 is selected, with the following characteristics:

- High average wholesale market price
- Low wholesale energy market price volatility (measured as the standard deviation of prices during the year)
- High average contingency FCAS prices;

The selection aims to strike a balance of favourable and unfavourable market conditions that will affect the value of the regulatory developments discussed in the analysis to provide suitable estimates of the value different regulatory options can provide.

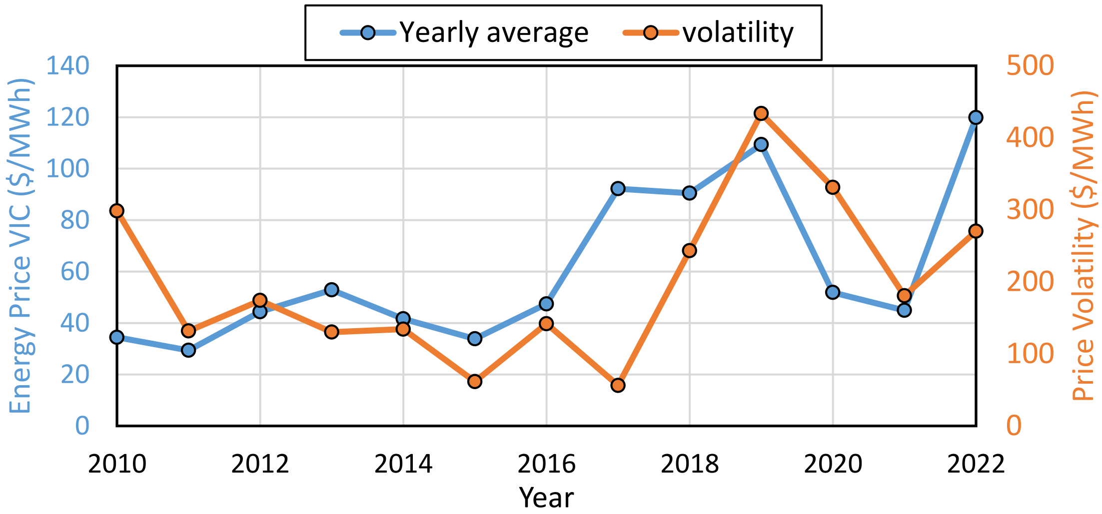

Figure 3. Historical yearly average wholesale market price and price volatility (measured as standard deviation) in Victoria from 2010 to 2022

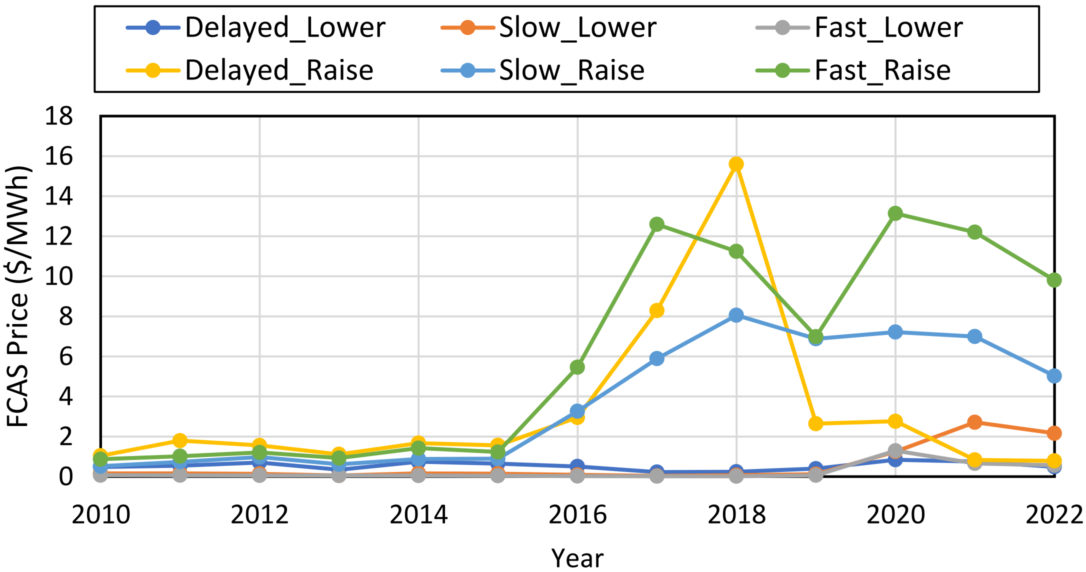

Figure 4. Historical yearly average prices for the six contingency FCAS markets in Victoria from 2010 to 2022

2.3 Retail Data

From Project 8 network use of service (NUoS) are considered to be applied to customer imports at the MV/LV transformer level. In practice NUoS are charged to each customer individually, according to the energy imports measured by their smart meter at their point of connection with the LV network. However, given that Project11 is only modelling the MV network and only has access to data aggregated at MV/LV transformer level, NUoS are charged to the aggregate demand at each MV/LV transformer, providing an estimate of the network charges of customers.

In the analysis fixed costs (cents/day) are not considered as these costs cannot be optimized within the microgrid operation (these are charged daily regardless of the customer imports or exports). All customers in both Donald and Tarnagulla are assumed to follow the Residential time-of-use (ToU) tariff, and prices follow the indicative pricing schedule published by Powercor for 2023/2024 [2] during the whole horizon of the economic assessment. Peak usage is assumed to occur from 4:00 pm until 9:30 pm (both included), aligned with latest developments of network tariffs aiming to reduce evening peak for PV-rich systems.

Table 3. NUoS for customer imports charged at MV/LV transformer level

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

Additionally, retail rates are estimated for comparison purposes in the different test cases. Retail rates are extrapolated from the NUoS rates, which are assumed to be equal to 40% of the total retail rate customers are subject to. Feed-in tariffs for customer exports are considered as well, 6 cents/kWh is selected as an estimate based on the Victorian minimum feed-in tariff equal to 5.2 cents/kWh.

Table 4. Retail rates for customer imports and exports

Network Tariff	Usage Peak (cents/kWh)	Usage off-Peak (cents/kWh)	Feed-in tariff (cents/kWh)
Residential ToU	43.1	10.8	6

Additionally, customer retail rates are subject to distribution loss factors (DLF) which vary depending on the customer connection to account for the losses in the distribution system. The retail rates in each scenario presented in Section 2 are charged at different levels and therefore are subject to different DLF as presented in Table 5. This is relevant, as given the model characteristics, when retail rates are charged at the community interface with the upstream grid the losses within the MV network of the community are accounted for, as it would occur in practice in the implementation of community-level tariffs. On the other hand, when retail rates are charged at MV/LV transformer level these losses are not accounted. Therefore, when retail rates at charged at customer-level in the different scenarios, they are charged at the LV side of the distribution transformer at 240/415 V and are subject to DLF-D according to Table 5. When retail rates are charged at the interface of the community with the upstream grid, the DLF corresponds to the case of connection with a sub-transmission 22 kV line, therefore are subject to DLF-A. For the case of Donald and Tarnagulla, considering is part of the long sub-transmission Powercor the DLF considered are the following for each scenario:

- **Retail rate charged at customer MV/LV transformer level:** DLF-D = 1.09
- **Retail rate charged at community interface level:** DLF-A = 1.0373

Table 5. Approved network average DLF [3]

Table 10 Approved network average DLFs

Distributors	Distribution loss factors					
	Type	DLF A	DLF B	DLF C	DLF D	DLF E
Jemena	Short Sub-transmission	1.0042	1.0087	1.0172	1.0373	1.0430
	Long Sub-transmission	1.0124	1.0169	1.0253	1.0455	1.0512
CitiPower	Short sub-transmission	1.0040	1.0117	1.0153	1.0412	1.0500
Powercor	Short sub-transmission	1.0035	1.0088	1.0324	1.0562	1.0637
	Long sub-transmission	1.0373	1.0426	1.0662	1.090	1.0975
AusNet Services	Short sub-transmission	1.0036	1.0113	1.0286	1.0494	1.0570
	Long sub-transmission	1.0269	1.0345	1.0519	1.0726	1.0802
United Energy	Short sub-transmission	1.0039	1.0091	1.0149	1.0384	1.0525
	Long sub-transmission	1.0187	1.0240	1.0298	1.0533	1.0673

Notes:

- DLF- A is the distribution loss factor to be applied to a second-tier customer or market customer connected to a sub-transmission line at 66 kV or 22 kV.
- DLF- B is the distribution loss factor to be applied to a second-tier customer or market customer connected to the lower voltage side of a zone substation at 22 kV, 11 kV or 6.6 kV.
- DLF- C is the distribution loss factor to be applied to a second-tier customer or market customer connected to a distribution line from a zone substation at voltage of 22 kV, 11 kV or 6.6 kV.
- DLF- D is the distribution loss factor to be applied to a second-tier customer or market customer connected to the lower voltage terminals of a distribution transformer at 240/415 V.
- DLF- E is the distribution loss factor to be applied to a second-tier customer or market customer connected to a low voltage line at 240/415 V.

2.3.1 Additional network tariffs under study

2.3.1.1 Community battery trial tariff

The BESS can be subject to network charges based on Powercor published CB Network trial tariff for non-distributor owned batteries[4]. The fixed rate is omitted from the techno-economic results and value streams, as it is a fixed cost and the BESS operation cannot be optimized to reduce it.

Table 6. Non-distributor owned community battery trial tariff [4]

Time Band	Fixed rate (cents/day)	Import Rate (cents/kWh)	Export Rate (cents/kWh)
10 AM – 3 PM	45	-1.5	0
4 PM – 9 AM		25	-1
All other times		0	0

2.3.1.2 HV customer tariff for the community interface

It will also be studied the scenario in which network charges are applied to the community as a whole (at the point of connection of the community with the upstream grid) using the HV customer network tariff as outlined by Powercor in its Pricing proposal for 2023/2024 [2], presented in Table 7. In this case, the BESS can be operated to reduce the network charges of the community as a whole.

Table 7. NUoS for the microgrid charged at the point of connection of the microgrid with the upstream grid.

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

2.4 Demand Response data

In some scenarios during summer, microgrid DER resources can provide demand response (DR) as a form of congestion management to the upstream grid. DR price data available from other Victorian DNSP is used to select prices and duration of the required DR service [5]. Essentially, DR is modelled as a function of availability and delivery. Availability corresponds to a firm capacity DER provide, effectively limiting the DER output during a required period of time (in this case, during the summer months). DER receive a payment for the capacity they have available for DR, contractually agreeing to be able to increase their generation (or reduce its demand in case of batteries) equal to the available capacity when the DR service is called. Delivery corresponds to the actual times in which DR is required and the resources increase their energy output, effectively reducing the net demand of the community. DR delivery is assumed to take place at times of high wholesale market prices. The techno-economic details for DR service are included in Table 8

Table 8. Demand Response (DR) techno-economic details.

Network Tariff	DR Availability	DR Delivery
Price	$26,000/MW	$750/MWh
Duration	3 months	1 event per month and 60 minutes per event

3 Results and Discussion

3.1 Motivation for energy communities and microgrids

In the context of increasing uptake of privately-owned DER, and the rising interest of energy community frameworks there is a fundamental question that needs to be answered: is it more economically efficient to incentivize customers to adopt their own private DER (e.g., PV, BESS) or to invest in larger community resources.

To provide some insights on this fundamental question two scenarios are generated for Tarnagulla current conditions. In Tarnagulla, all nine MV/LV transformers present similar PV penetration, with a ratio of peak demand to peak PV generation ranging from 44% to 60%. As per the data retrieved from Project 7, the BESS penetration is negligible. The two scenarios generated are the following:

- **Distributed BESS:** Installing one-hour duration BESS in each MV/LV transformer. Each BESS rating is equal to the maximum PV generation in the MV/LV transformer, with a total aggregate installed BESS equal to 185kW/185kWh. Each BESS is operated to minimise the total retail costs of the customers that are connected to the same MV/LV transformer, charged at MV/LV transformer level, with DLF-D = 1.09.
- **Centralized BESS:** Installing a centralized one-hour duration BESS in Bus 7 (Commercial Welsh). The BESS rating is equal to the total maximum PV generation in Tarnagulla, equal to 185kW/185kWh. The BESS is operated to minimise the total retail costs of the town, which are charged at the interface of the community with the upstream grid, with DLF-A = 1.0373. In this sense the centralized BESS operation is coordinated with all the PV and demand in the community.

The same scenarios are generated for Donald, using total installed BESS equal to 775/775kWh.

The results in Figure 5 present the total retail costs the Tarnagulla community would be subject to in each of the weeks of study (i.e., summer, winter and mid-season). The results highlight that in all cases, the centralized BESS that is operated in coordination with all Tarnagulla customer demand and privately-owned PV, to provide arbitrage to the community as a whole results in lower costs. The same results are provided for Donald in Figure 6, with equivalent conclusions.

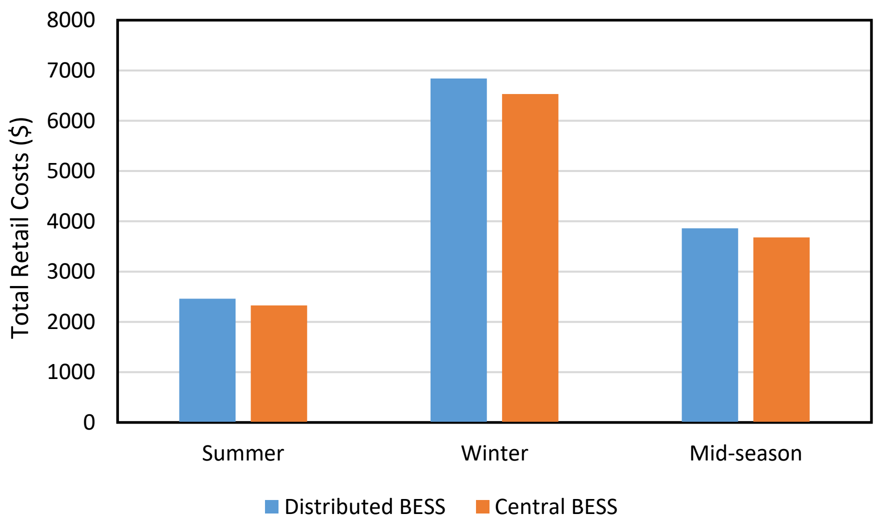

Figure 5. Comparison of total retail costs for Distributed BESS and Centralized BESS scenarios in Tarnagulla

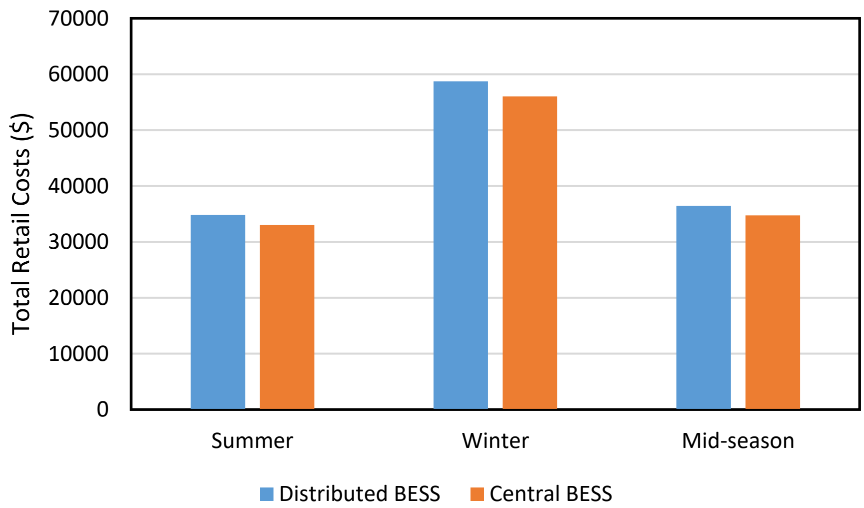

Figure 6. Comparison of total retail costs for Distributed BESS and Centralized BESS scenarios in Donald

Finally, from the results presented in Figure 5 and Figure 6, an estimate on the potential annual savings for the community with a centralized BESS as opposed to privately-owned distributed BESS are presented in Table 9 and Table 10. The results highlight that with the same total BESS installed in the community, a centralized BESS operated in coordination with all customer demand and privately-owned PV generation to minimise the total retail costs of the community, charged at the interface of the community with the upstream network, annual savings can be significant. This annual benefits for the community come just from its operation, and other benefits such as reduced installation and maintenance costs that arise from having a single BESS are not considered, which could potentially further support the case for centralized DER in the community. Additionally, it must be highlighted that even though the order of magnitude in terms of the value of centralized BESS is strikingly different in each town, the relative improvement is the same, equal to 5%. Therefore, a larger community (i.e., Donald) does not seem to provide relative benefits with respect to a smaller community (i.e., Tarnagulla).

Table 9. Estimate of the annual savings with a centralized BESS as opposed to distributed BESS in Tarnagulla

Representative Weeks	Number weeks/year	Distributed BESS ($)	Centralized BESS ($)
Summer	12	2459.736	2327.802
Winter	12	6841.034	6530.347
Mid-season	28	3862.343	3679.786
Annual Costs ($)	52	219,755	209,332
Value of Centralized BESS ($)			**10,423 (~5% improvement)**

Table 10. Estimate of the annual savings with a centralized BESS as opposed to distributed BESS in Donald

Representative Weeks	Number weeks/year	Distributed BESS ($)	Centralized BESS ($)
Summer	12	34,830.58	33,030.82
Winter	12	58,729.1	56,047.64
Mid-season	28	36,447.83	34,735.84
Annual Costs ($)	52	2,143,255	204,1545
Value of Centralized BESS ($)			**101,711 (~5% improvement)**

Implications for regulatory development

- The results and discussion highlight that centralized DER, operated in coordination with the whole community, as opposed to privately-owned DER, operated for the benefit of the individual customer has potential to provide further value.
- Given that in its simpler form (reducing energy costs subject to energy retail rates) community DER can potentially be more economically efficient than privately-owned DER, the study of community frameworks is highly relevant in the transition towards low-carbon power system aligned with (National Electricity Objectives) NEO principles.
- However, it must be noted that the granularity of the proposed study is MV network, and customers are aggregated at MV/LV transformer level. Further accuracy on the implications of installing centralized DER as opposed to distributed and privately-owned DER can be achieved by including in the modelling the LV network and each specific customer. Nevertheless, complete individual smart meter customer data is not available.
- Finally, there are no significant differences between Donald and Tarnagulla in the relative improvement of centralized DER. The results display that the case for centralized DER is equally strong in both larger and smaller communities, under equivalent conditions.

3.2 Access to markets and services

With the foundations laid on the motivation to study community frameworks, which can potentially enable further benefits to a community when compared to privately-owned DER, different regulatory frameworks that enable community DER to provide value to the communities are studied.

3.2.1 Only energy arbitrage services

The following scenarios focus on the case of centralized BESS, with different scenarios representing different frameworks in which the centralized BESS can provide energy services to the community:

- **Community retail rate:** the BESS is operated to minimise the total retail costs and network charges of the town, which are charged at the interface of the community with the upstream grid. The residential ToU retail tariff presented in Table 4 is selected for this purpose. for In this sense the centralized BESS operation is coordinated with all the PV and demand in the community.
- **Community wholesale (WS) market:** the whole community imports and exports are subject to wholesale market prices, charged at the interface of the community with the upstream grid. The centralized BESS is operated in coordination with all PV and demand in the community to minimise the total costs of the community subject to wholesale market prices. Network charges are applied at MV/LV transformer level.
- **BESS front-of-the meter (FOM) wholesale (WS) market + Customer retail rate:** the centralized BESS is operated to accrue revenues from wholesale market arbitrage, charged

FOM of the BESS. In this sense, the BESS operation is not coordinated with the community demand and PV to maximize revenues, and its operation is therefore independent from the community operation. The community demand and privately-owned PV are subject to retail rate and network charges charged at MV/LV transformer level.

The results in Figure 7 and Figure 8 present the total costs and benefits to supply energy to the community during the representative summer week for the three different scenarios. In the scenarios “Community retail rate” and “Community WS market” the centralized BESS operation is orchestrated with the customer demand and privately-owned PV to minimize community energy costs. In the “BESS FOM WS market + Customer retail rate”, the BESS is operated independently of the rest of the community to accrue revenues from wholesale market arbitrage, whereas customers are subject to the usual retail rates. The results highlight that the coordinated operation of the BESS with the community results in lower energy costs and thus further value provided to the community, as both “Community retail rate” and “Community WS market” result in lower costs that when the BESS is operated FOM to accrue revenues from wholesale market arbitrage (which could be potentially shared with the community members). Additionally, “Community retail rate” results in higher energy costs than “Community WS market”.

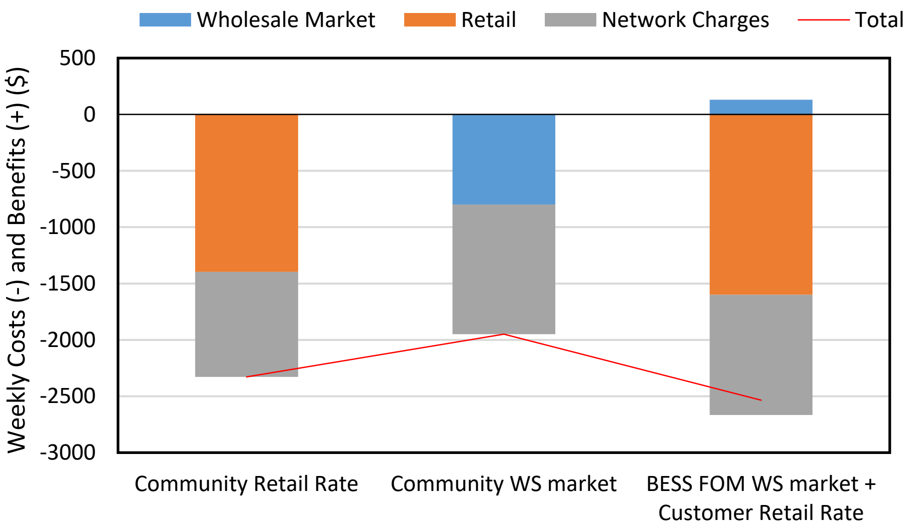

Figure 7. Comparison of the three scenarios for the centralized BESS to provide energy services to the community for the representative summer week in Tarnagulla

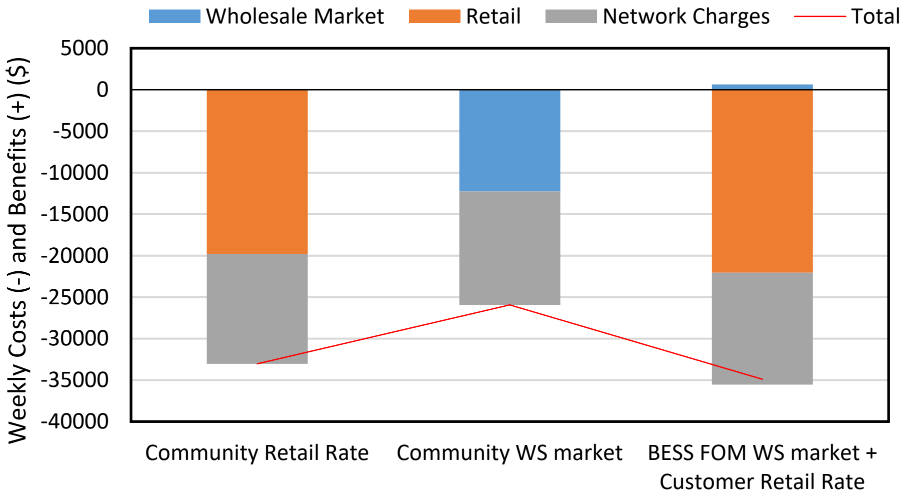

Figure 8. Comparison of the three scenarios for the centralized BESS to provide energy services to the community for the representative summer week in Donald

Table 11 summarizes the total energy costs for Tarnagulla in each of the representative week for each scenario, to then provide an estimate of the annual costs. The trends displayed in the summer representative week are also seen in the remaining representative weeks, with the exception of winter week, where "BESS FOM WS market + Customer retail rate" results in total lower energy costs than "Community retail rate". However, the estimated annual costs remain lower in the scenarios that enable the coordination of the centralized BESS with the community demand and privately-owned PV. To this end, the annual value of coordination is estimated by comparing the total energy costs for "Community retail rate" and "Community WS market" with the "BESS FOM WS market + Customer retail rate". The value of coordination is estimated to be significant, especially in the "Community WS market". Finally, the value of the community facing wholesale energy markets as opposed to retail rates is estimated by comparing "Community retail rate" and "Community WS market", displaying a potential energy cost reduction for the community, and therefore more value for the energy community project can provide.

Table 11. Estimate of the annual energy costs for Tarnagulla with a centralized BESS and different frameworks to provide energy arbitrage services

Representative Weeks	Number weeks/year	Community Retail Rate ($)	Community WS market ($)	BESS FOM WS market + Customer Retail Rate ($)
Summer	12	2327.80	1949.24	2534.77
Winter	12	6530.35	6012.00	6508.37
Mid-season	28	3679.79	3489.01	3799.38
Annual Costs ($)	52	**209,331**	**193,227**	**214,900**
Value of Coordination ($)		**5,569**	**21,673**	**N/A**
Value of WS market participation ($)		**N/A**	**16,105**	**N/A**

Table 12 represents equivalent results for Donald. Nevertheless, the results indicate that for Donald there is further value in wholesale market participation than coordination. Whereas in the summer week “Community Retail Rate” results in total lower costs, in the remaining weeks (winter and mid-season) it results in higher costs than “BESS FOM WS market + Customer Retail Rate”, displaying overall lower value of coordination and higher value in wholesale market participation. Two relevant aspects must be considered to understand these differences between Donald and Tarnagulla. First, Tarnagulla has considerable higher penetration of privately-owned PV than Donald, while Tarnagulla displays more value in coordination. Second, during the summer week (characterized by higher PV generation) in Donald “Community Retail rate” results in lower costs that “BESS FOM WS market + Customer Retail Rate”, and thus there is more value in coordination than market facing BESS. Given this, one can infer that higher privately-owned DER penetration in the community results in higher value of coordination. On the other hand, if in a community there is lower penetration of privately-owned DER, coordination displays less value and having a market facing centralized DER might result in further benefits for the community. Nevertheless, further analysis is required to provide more conclusive results and trends.

Table 12. Estimate of the annual energy costs for Donald with a centralized BESS and different frameworks to provide energy arbitrage services

Representative Weeks	Number weeks/year	Community Retail Rate ($)	Community WS market ($)	BESS FOM WS market + Customer Retail Rate ($)
Summer	12	33,030	25,936	33,075
Winter	12	56,047	52,427	54,741
Mid-season	28	34,735	32,479	34,396
Annual Costs ($)	52	2,041,545	1,849,773	2,016,898
Value of Coordination ($)		**-24,646**	**167,124**	**N/A**
Value of WS market participation ($)		**N/A**	**191,771**	**24,646**

Implications for regulatory development

- The main finding of this analysis is that for provision of energy arbitrage services, centralized DER coordination with the community demand and privately-owned DER results in further value than its independent market participation. Therefore, frameworks that enable aggregate community operation, where the centralized DER can provide arbitrage to the community energy needs as a whole can unlock further benefits for the community.
- Nevertheless, the results indicate that higher penetration of privately-owned DER in a community is a key driver for more value in coordination of the centralized DER with the rest of resources.
- While the community being subject to wholesale market prices presents opportunities to reduce costs it also entails risks, as it might be subject to high price periods, therefore further analysis is required to provide better estimates on potential risks and benefits from being subject to wholesale market prices.
- It must be noted that being subject to wholesale market prices does not entail end-customers are subject to those prices. A third-party taking the role of community/microgrid operator can offer a competitive retail rate for customers in the community, with its profits arising from the difference between the revenues from the retail rate offered to customers, and the community net position from wholesale market participation. The key aspect that requires a more detailed analysis is to understand if the potential value of the community participating in the wholesale market as opposed to being subject to a community retail rate allows for the third-party to

accrue sufficient profits while proposing a competitive retail rate (lower retail rate than the NEM retailers) for the community customers.

3.2.2 Co-optimization of energy arbitrage and FCAS

The following scenarios focus on the case of centralized BESS, with different scenarios representing different frameworks in which the centralized BESS can co-optimize energy services and FCAS market participation:

- **Community retail rate:** the BESS is operated to minimise the total retail costs and network charges of the town, which are charged at the interface of the community with the upstream grid. In this sense the centralized BESS operation is coordinated with all the PV and demand in the community. Additionally, the BESS can participate in FCAS market.
- **Community wholesale (WS) market:** the whole community imports and exports are subject to wholesale market prices, charged at the interface of the community with the upstream grid. The centralized BESS is operated in coordination with all PV and demand in the community to minimise the total costs of the community subject to wholesale market prices. Network charges are applied at MV/LV transformer level. Additionally, the BESS can participate in FCAS market.
- **BESS front-of-the meter (FOM) market:** the centralized BESS is operated to accrue revenues from wholesale market arbitrage and FCAS, charged FOM of the BESS. In this sense, the BESS operation is not coordinated with the community demand and PV to maximize revenues, and its operation is therefore independent from the community operation. The community demand and privately-owned PV are subject to retail rate and network charges charged at MV/LV transformer level.
- **Virtual Power Plant (VPP):** all the DER in the community are orchestrated as part of a VPP, accessing the suitable markets. In the case of privately-owned PV, as a part of the VPP this only entails FCAS market participation, as VPP operator conventionally does not provide energy services to customers, as it would require two different meter architecture for the customer. The centralized BESS is operated to accrue revenues from wholesale market arbitrage and FCAS, charged FOM of the BESS, with its operation coordinated with the privately-owned PV FCAS market participation. The community net demand (energy demanded and generated by the privately-owned PV) are subject to retail rate and network charges charged at MV/LV transformer level.

The results in Figure 9 and Figure 10 present the total costs to supply energy to the community during the representative summer week for the four different scenarios. Importantly, the results display that all the different scenarios enable similar revenues accrued from FCAS participation. Given that the different scenarios mainly differ in the provision of energy services to the community, it demonstrates that different community set-ups to provide energy services allow for the co-optimization of energy services and FCAS. In turn, this results in improved net positions (less operational costs for the community) when compared to only providing energy services. When comparing “Community Retail Rate”, “Community WS market” and “BESS FOM market” equivalent conclusions to the case of only providing energy services can be extracted: there is significant value in coordination of the centralized BESS operation, when compared to its independent operation. Finally, the “VPP” scenario enables FCAS participation of privately-owned PV (coordinated with the centralized BESS market participation), which is the main difference with the “BESS FOM market” scenario. Whereas the FCAS revenues are slightly higher in the VPP case, the results highlight that the privately-owned PV are prioritized to provide energy arbitrage to the customers, and their FCAS participation is not significant. Whereas in the current conditions in Donald and Tarnagulla, the results indicate a VPP scenario might not provide a significant benefit, further analysis is required to understand the potential of a VPP scenario with further privately-owned DER, including BESS.

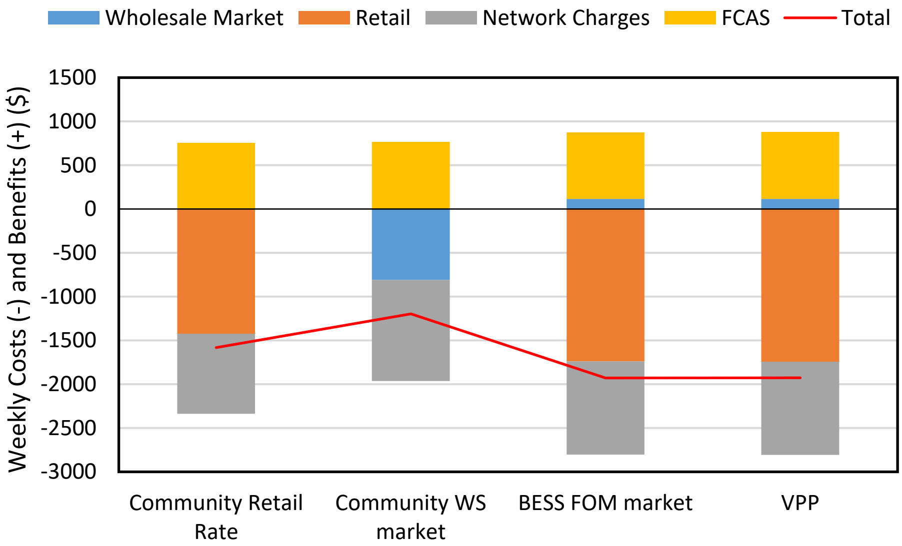

Figure 9. Comparison of the four scenarios for the centralized BESS to co-optimize energy and FCAS services for the representative summer week in Tarnagulla

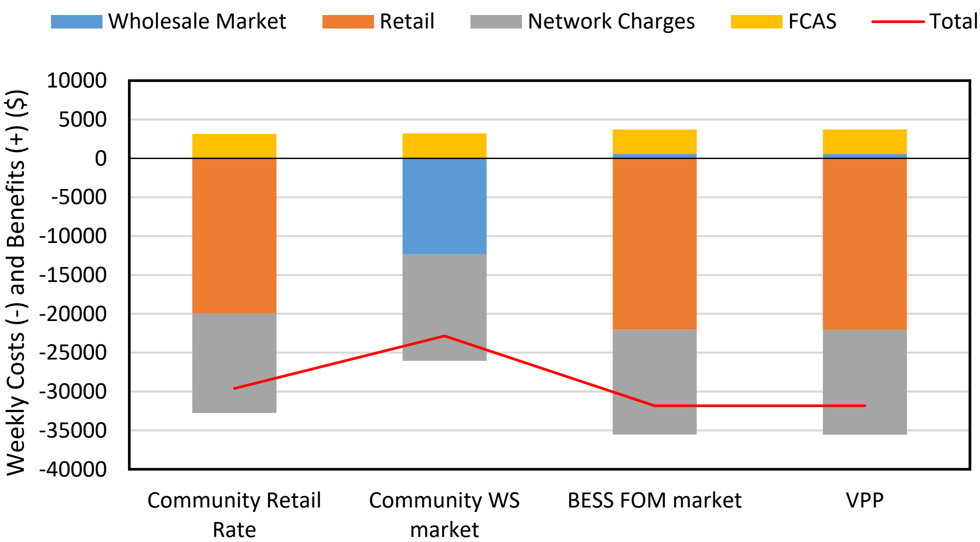

Figure 10. Comparison of the four scenarios for the centralized BESS to co-optimize energy and FCAS services for the representative summer week in Donald

Implications for regulatory development

- Enabling centralized DER to co-optimize the provision of different services it is key to provide more value to the community, resulting in a significant improvement in its economic position, as opposed to only providing energy services.
- The different scenarios for the centralized DER to provide energy services can allow for co-optimization of FCAS market participation. Therefore, FCAS participation is not a determining factor to decide which energy service framework is more appropriate (i.e., Community retail rate, Community WS market or BESS FOM).

3.3 Network tariffs

The following scenarios focus on the case of centralized BESS only providing energy services via wholesale energy market participation. The centralized BESS is operated in coordination with all PV and demand in the community to minimise the total costs of the community subject to wholesale market prices. The different scenarios correspond to different network tariffs applied to the community.

- **Business-as-usual (BAU) network use of service (NUoS):** network charges are applied at MV/LV transformer level for customers following the ToU residential tariff. The Centralized BESS is not subject to a network tariff.
- **BAU NUoS + Community battery (CB) trial tariff:** network charges are applied at MV/LV transformer level for customers following the ToU residential tariff. The Centralized BESS is subject to the CB trial tariff.
- **Residential NUoS at community level:** network charges are applied at the community interface with the upstream grid, following the ToU residential tariff.
- **Community NUoS:** network charges are applied at the community interface with the upstream grid, following the HV customer tariff, which entails usage and peak demand charges.

Figure 11 and Figure 12 present the total costs to supply energy to Tarnagulla and Donald during the representative summer week for the four different scenarios with distinct network tariff frameworks. “BAU NUoS” corresponds to a scenario in which the centralized BESS is not subject to a network tariff, and customers are subject to BAU tariffs charged at the MV/LV transformer level. Then, the scenario “BAU NUoS + CB trial tariff” explores the impact of charging the centralized BESS the community battery (CB) trial tariff. The results of the “BAU NUoS + CB trial tariff” display that the BESS is able to co-optimize the network tariff and wholesale energy market arbitrage, resulting in a slightly improved position, by accruing revenues through CB trial tariff arbitrage, albeit these revenues have very little significance when compared to the remaining costs the community is subject to. The scenario “Residential NUoS at community level” charges the same network tariff as the previous scenarios, but at the community interface, which allows the centralized BESS to provide arbitrage on the community usage, in turn resulting in a slight reduction of the community network charges on usage.

The scenario “Community NUoS” proposes a significant change in framework, charging the NUoS at the interface of the community with the upstream grid, both in terms of usage as well as capacity (peak demand). This allows the centralized BESS to provide significant technical benefits and cost-efficiently use the upstream network assets. Nevertheless, the HV customer network tariff has considerably lower prices on energy usage than the residential ToU tariff. This is due to the residential ToU tariff considering the network costs from transmission network until the LV network which residential customers are connected to, whereas the HV customer network tariff does not include the costs associated with the MV and LV networks. As discussed in Project 8, this issue can be addressed by introducing a local use of service (LUoS) within the community, which guarantees that the DNSP costs to operate and maintain the MV and LV network are recovered. LUoS as a cost recovery mechanism is displayed in Figure 11 and Figure 12. More details on a methodology to calculate LUoS prices to guarantee cost recovery of network assets can be found in Project 8. Whereas the community is subject to the same total costs, in the “Community NUoS” scenario, the community is subject to three different charges. Although increasing complexity, this can result in technical benefits and a more cost-efficient use of the network assets. In particular, with respect to the peak demand of the community, as displayed by Figure 13 and Figure 14.

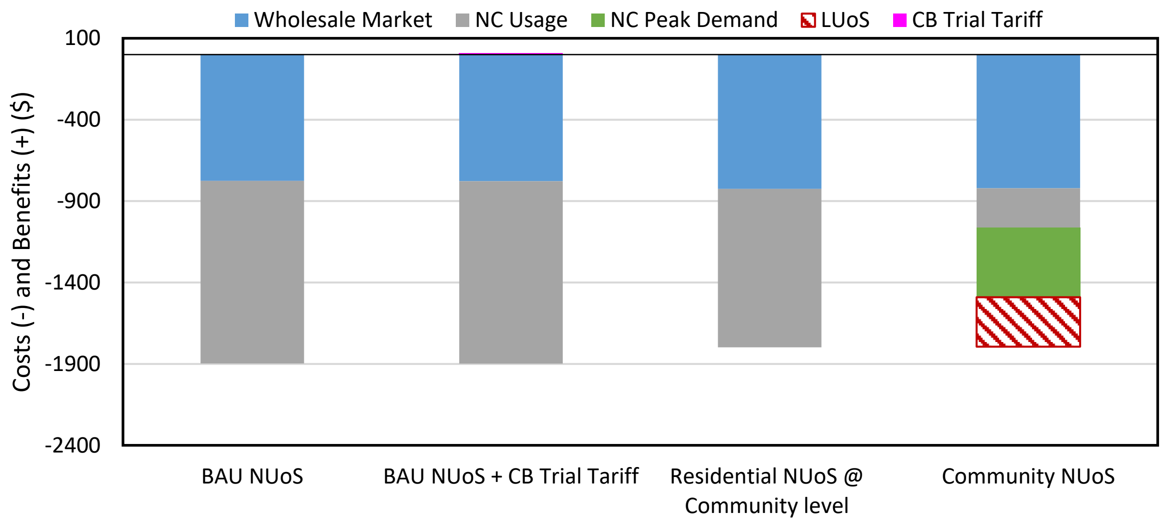

Figure 11. Comparison of the four network tariffs scenarios for the representative summer week in Tarnagulla

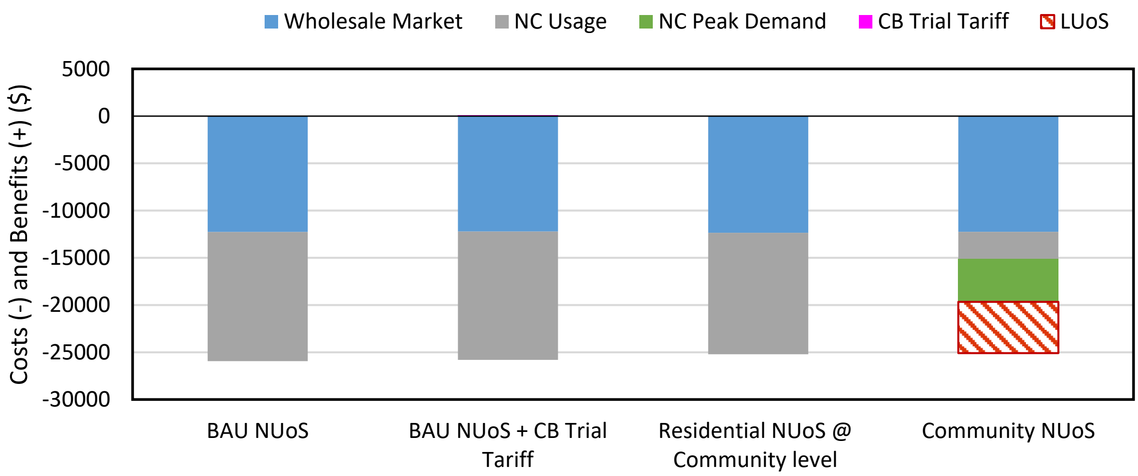

Figure 12. Comparison of the four network tariffs scenarios for the representative summer week in Donald

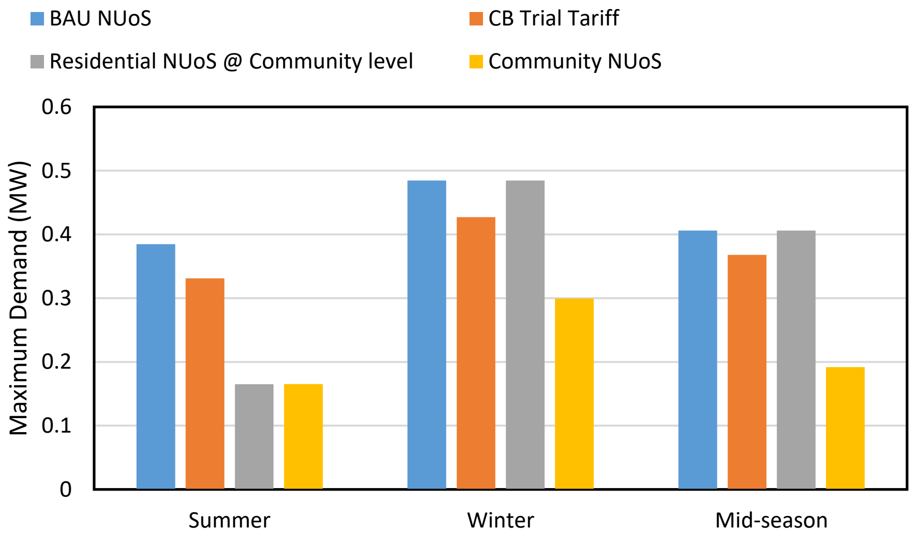

Figure 13. Maximum community demand in Tarnagulla for the different network tariff scenarios

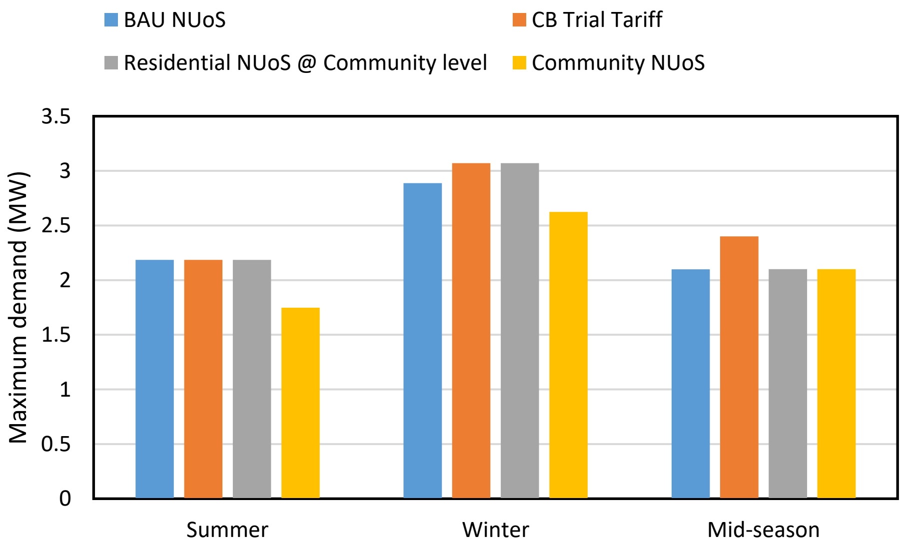

Figure 14. Maximum community demand in Donald for the different network tariff scenarios

3.3.1 Technical impact of network tariffs: Tarnagulla example

Beyond the economic results there are significant technical benefits that arise from implementing the community network tariff. Further analysis on the technical implications of community network tariffs will be carried out using Tarnagulla as an example. To display the impact the different network tariff scenarios, Figure 15 presents the different price signals ($/MWh) that affect the centralized BESS, Figure 16 presents the centralized BESS dispatch and Figure 17 the community energy imports and exports with the upstream grid. The scenario “Residential NUoS at community level” is omitted for the following analysis.

Figure 15 presents the wholesale energy market prices, which the community is subject to. The centralized BESS is operated to minimise the costs from purchasing energy from the wholesale market and maximise the costs from selling energy to the wholesale market. Additionally, the “CB Tariff imports” corresponds the price signal for imports (charging) that the centralized BESS is subject to in the scenario “BAU NUoS + Community battery (CB) trial tariff”. Finally, “Community tariff” corresponds to the network charges the community is subject to in the “Community NUoS” scenario, charged at the interface of the community with the upstream grid, for which the centralized BESS can provide arbitrage. It must be noted that in the “Community NUoS” scenario, there is a peak charge that has not been presented, but the centralized BESS is co-optimizing along with the usage charges.

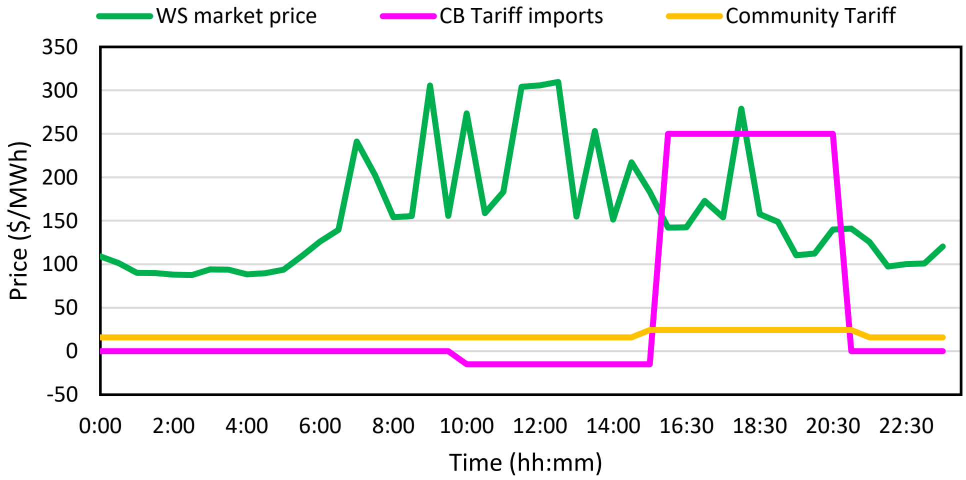

Figure 15. Price signals on energy imports/exports for the community during a representative winter day.

Figure 16 presents the BESS dispatch in the different scenarios, as a result of the different price signals that the centralized BESS and/or community is subject to. During this day, wholesale energy markets are high with several price spikes, which is reflected in the centralized BESS dispatch aiming to minimise the costs from purchasing energy from the wholesale market. In all scenarios the BESS discharges during the price spikes and charges during lower price periods. The CB trial tariff affects BESS dispatch, as it avoids charging at 4:00 pm, when compared to the original case of “BAU Network tariff”, which can potentially avoid peak demand conditions in the local network. The usage network charges in “Community network tariff” have limited impact in the BESS dispatch, as this price signal is orders of magnitude lower than the wholesale market price. Nevertheless, BESS charging is affected by the peak demand charge, reducing the charging power during several instances e.g., 8:00 AM, 10:00 AM, and importantly, 10:00 PM, when it discharges rather than charging like the two other scenarios.

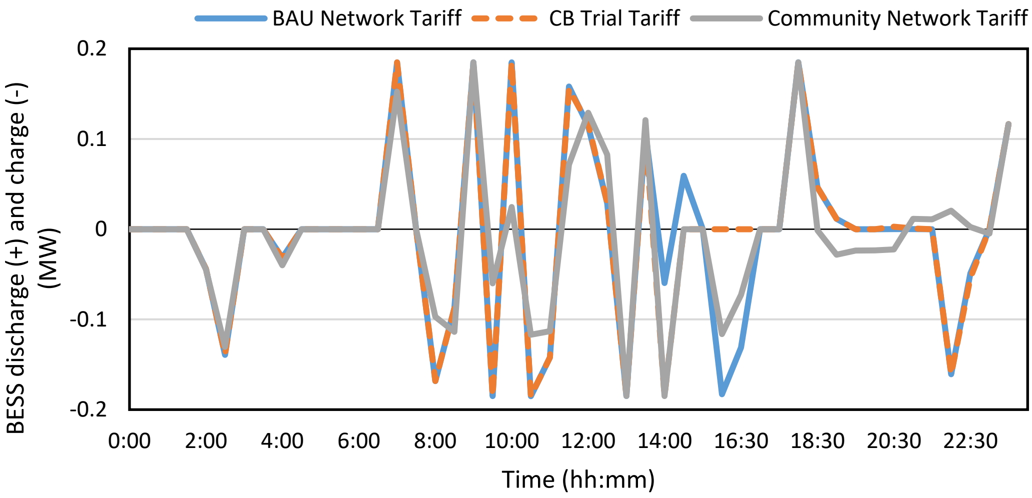

Figure 16. BESS dispatch for the different scenarios during a representative winter day.

Figure 11 presents the impact of the different network tariffs in the community imports and exports with the upstream grid. It additionally displays the community net demand, which does not include the BESS dispatch and it is equal in all scenarios. The BESS has an impact in the aggregate community imports and exports, following wholesale market prices. Importantly, in the BAU Network Tariff scenario, peak demand in the community is significantly increased in the evening, in particular at 4:00 PM and 10:00 PM. The implementation of the CB Trial Tariff effectively reduces the peak demand at 4:00 PM, but not at 10:00 PM, when the BESS imports are subject to 0 cents/kWh. On the other hand, the community network tariff, and in particular the peak demand charge effectively avoids the peak demand of the community at 10:00 PM, which is caused by the BESS charging during a low price period. In fact, peak demand is controlled to 0.3 MW in all instances (e.g., 8:00 AM, 10:00 AM, 11:00 AM) whereas in the other two scenarios, the community demand reaches between 0.36 MW and 0.49 MW.

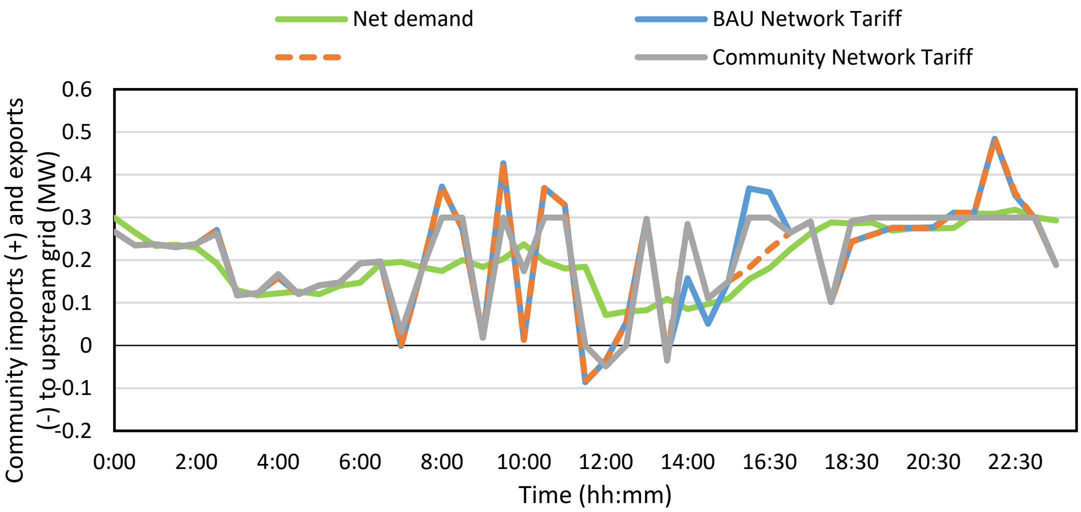

Figure 17. Community imports and exports to the upstream grid in the different scenarios during a representative winter day.

In the selected winter day, the discussion on peak demand reduction displays the case of community peak demand increasing as a result of the BESS wholesale energy market arbitrage, and how peak demand charges effectively limits the possible impact of BESS operation increasing the peak demand conditions. Nevertheless, this case did not demonstrate the ability of the BESS to reduce the community peak net demand. Figure 18 displays the community imports and exports during a summer day for the different scenarios under study. In this case after 9:00 PM, the net demand of the community increases (as can be seen from the evolution of “Net demand”), which is the peak demand during this day. The HV network tariff applied at community level results in the BESS discharging during the peak demand conditions, effectively reducing the peak. On the other hand, the remaining two scenarios result in BESS charging at the same time as the peak demand of the day, which results in increasing the peak demand conditions. This demonstrates the peak demand charge not only limits possible adverse effects from the BESS operation, but can also reduce peak demand conditions of the community.

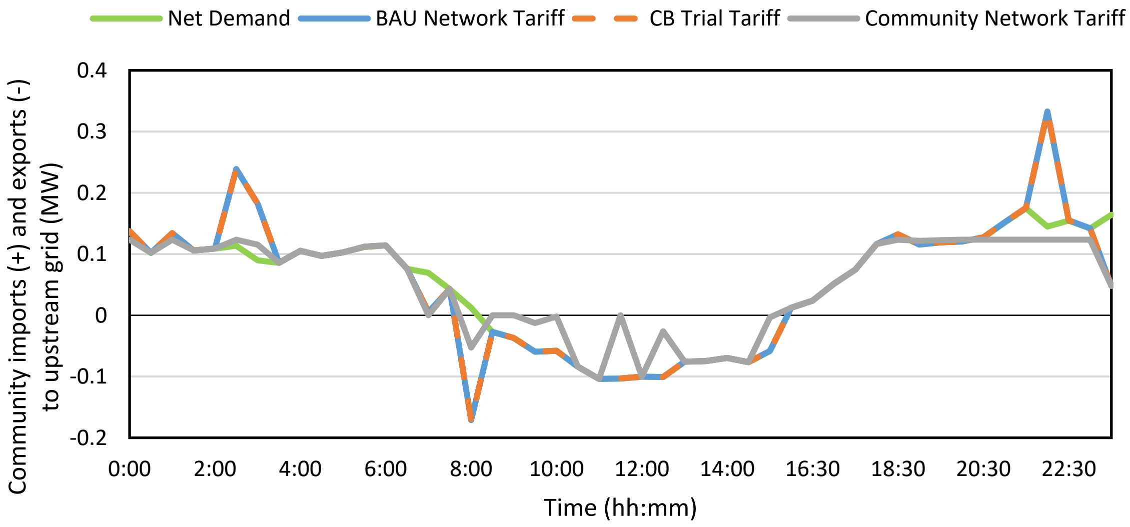

Figure 18. Community imports and exports to the upstream grid in the different scenarios during a representative summer day.

3.3.2 Community-level peak demand and usage charges

As previously discussed, the HV customer network tariff results in prices that are orders of magnitude lower than wholesale energy market prices. As a result, when analysing the impact of the “Community NUoS” scenario, the results mainly demonstrated the impact of the peak demand charge and did not demonstrate the impact of network charges on usage at the community interface with the upstream grid. The Residential ToU tariff applied at community level is comprised of higher prices, closer to the order of magnitude of wholesale energy prices. Therefore, can demonstrate the impact of network charges on usage. To understand the impact of different network tariff structures with the different usage and capacity (peak demand) components, the following scenarios are generated:

- **Usage Community NUoS (Residential ToU):** network charges are applied at the community interface with the upstream grid, following the ToU residential tariff.
- **Peak demand:** network charges are applied at the community interface with the upstream grid, following the HV customer tariff, but only comprised of peak demand charges
- **Usage Community NUoS (Residential ToU) + Peak demand:** network charges are applied at the community interface with the upstream grid, following the ToU residential tariff and including the peak demand charge from the HV customer tariff.

Figure 19 and Figure 20 present the total costs to supply energy to the community during the representative summer week for the three different scenarios that represent network tariffs comprised of different components (usage and/or peak demand). First, the results display all scenarios have equivalent performance in the wholesale market. Therefore, there is no significant advantage in terms of network tariff components and co-optimization of network tariff arbitrage with wholesale market arbitrage. Additionally, the results display the costs for the community with each network tariff component considered separately and when both components are in place. The results indicate that there are limited synergies between the usage component and the peak demand component. When the network tariff is comprised of both usage and peak demand components, the costs of each component for the community are very similar than the respective cases in which the community is subject to the single component in the network tariff. This indicates that essentially, there is no particular economic benefit for the community to be subject to a "Usage + Peak demand" tariff, as there are no synergies that arise in the operation to reduce both of these components. Therefore, it is important to understand the technical implications of including each component separately as opposed to combined to understand what can be the most adequate avenue for network tariffs of communities.

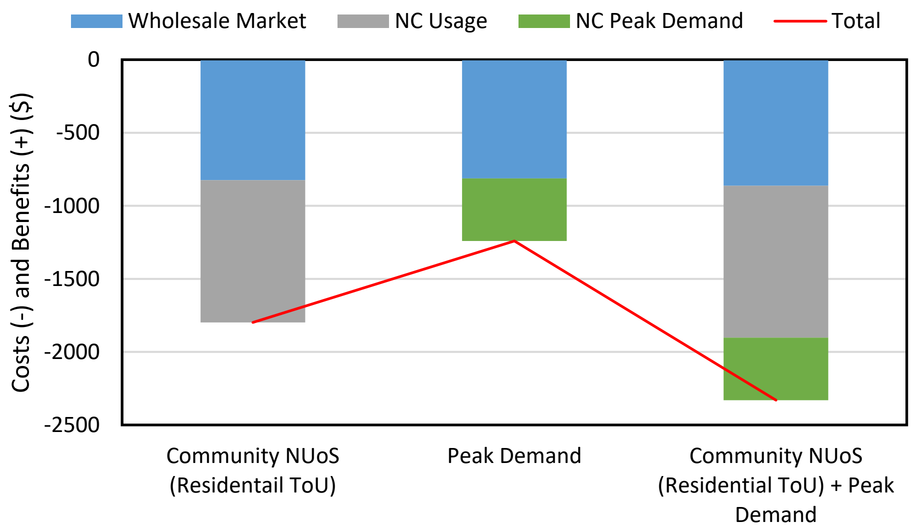

Figure 19. Comparison of the three network tariffs components for the representative summer week in Tarnagulla

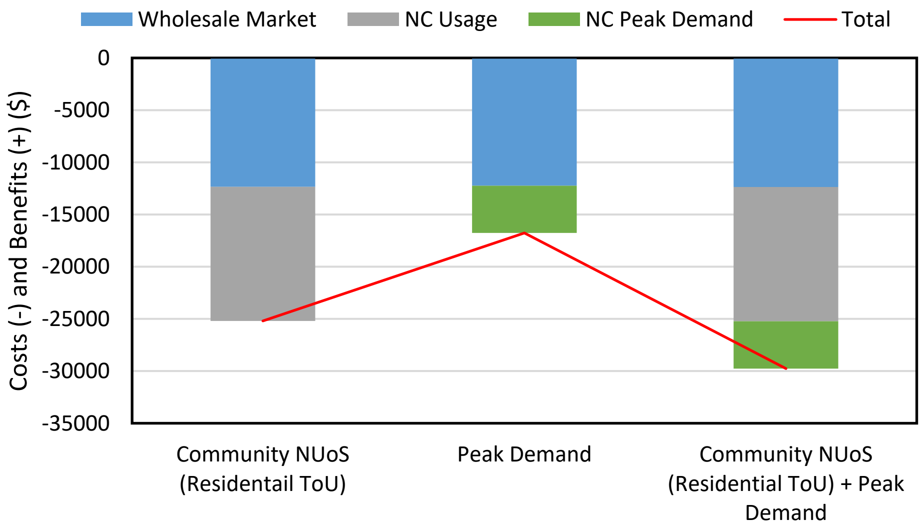

Figure 20. Comparison of the three network tariffs components for the representative summer week in Donald

3.3.3 Technical impact of usage and peak demand components: Tarnagulla example

To understand the implications of including the different network tariff components a representative summer day is selected. Figure 21 presents the costs on energy imports and exports the community is subject to. Compared to Figure 15, it is clear that the order of magnitude of the usage charges are considerably higher when considering the Residential ToU tariff as compared to the HV customer tariff. Therefore, the usage component will have a material impact on the BESS dispatch and therefore, the community operation. It must be noted that NUoS only charge imports and exports are not charged.

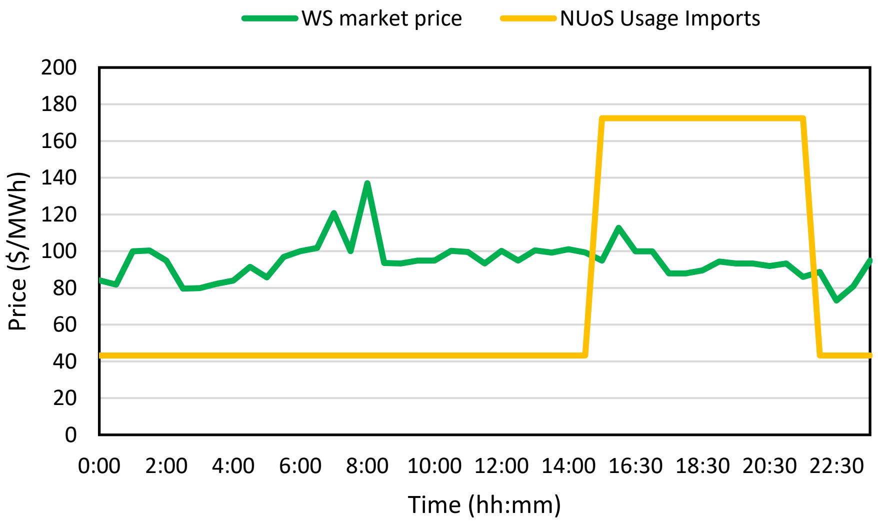

Figure 21. Price signals on energy imports/exports for the community during a representative summer day.

Figure 22 presents the impact of the different network tariff components in the community imports and exports with the upstream grid. It additionally displays the community net demand, which does not include the BESS dispatch and it is equal in all scenarios. With the current regulation, only energy imports can be charged. Therefore, when only including the usage component of the network tariff, the community results in more instances in which there is no exchanged energy with the upstream grid, rather than discharging and exporting energy to the upstream grid. Overall, the usage tariff results in an additional cost when the community is buying energy from the wholesale energy market, making more expensive for the community to import energy from the upstream grid. In this sense, self-consumption of the community is prioritized according to the combined price signals of wholesale energy market and usage charges. Nevertheless, when wholesale energy prices are lows peak demand conditions arise from the BESS dispatch, increasing the community peak demand. The results indicate that network charges on usage (imports) might be an adequate avenue to economically incentivize community self-sufficiency.

The main outcome of the peak demand charge is the control of the peak demand of the community, with the BESS being operated to control community imports from 5:00 PM onwards. Importantly, the community operation results in significantly less instances where the community total imports are zero, and results in higher exports to the upstream grid than the case with only usage component in the network tariff.

Finally, when both usage and peak demand components are present in the network tariff, the community operation displays the impact of both components. During most of the day, when the community net demand is lower than the peak demand, the community operation in “Peak + Usage” is aligned with the only “Usage” scenario. In the evening during peak demand conditions the community effectively reduces the peak demand to the same level as achieved by the scenario with only peak charge.

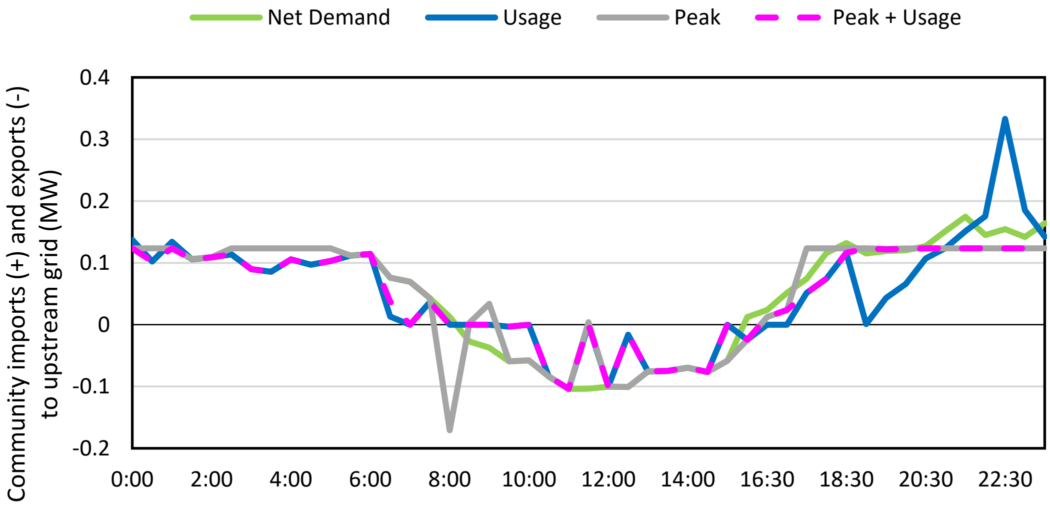

Figure 22. Community imports and exports to the upstream grid for the network tariffs with different components during a representative summer day

3.3.4 Trade-off energy savings and network tariffs

As identified by Project 8, and in the analysis presented in this report, energy savings to the community members (i.e., customers) is a key value stream. Assuming energy savings is a value allocated to the community members, provision of other services, might result in less energy savings for the community. It is therefore important to understand what trade-offs arise from the provision of different services. This is especially relevant in the case of network tariff arbitrage. First network tariffs price signals promote a technical benefit (i.e., cost-efficient use of network) which is then co-optimized with the participation in markets, being two value streams of different nature. Second, due to the purpose of network tariffs (DNSP network cost recovery) there are no significant savings that can be achieved i.e., the network assets remain the same and the costs needs to be recovered by the DNSP.

Figure 23 presents the increased energy costs of the community for the different scenarios of network tariff components at community level i.e., “Usage”, “Peak” and “Usage+Peak”. In all scenarios, introducing the network tariff at community level results in increased energy costs. Usage charges results in less increased costs than peak charges. These results indicate that there are existing synergies between the centralized DER providing arbitrage on network tariffs on usage and reducing the energy costs of the community.

In the representative summer week, the network tariff with only peak charge presents the lowest increase in energy costs. This is mainly due to the high PV generation combined with lower peak demand, which enables the centralized BESS to provide peak demand reduction without substantially impacting the energy costs. Nevertheless, in the remaining representative weeks, the reduction of peak demand results in higher increased energy costs. In this sense, the results highlight that the presence of high PV generation in the community is crucial for the centralized BESS to provide peak demand reduction, while minimally impact the reduction of energy costs.

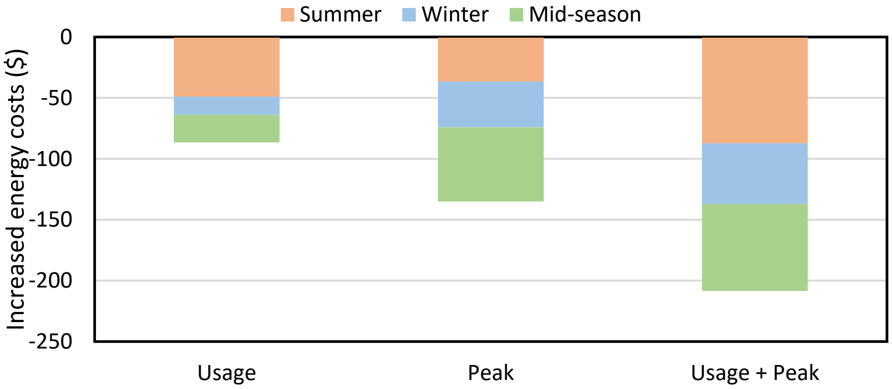

Figure 23. Increased energy costs for the community with the different components in Tarnagulla

Table 13. Annual increased energy costs when the community is subject to community-level network charges in Tarnagulla.

Cases	Energy Cost	Trade-off
BAU NuoS	99,977	N/A
Usage	101,381	1,403
Peak	102,574	2,597
Usage + Peak	103,620	3,643

Implications for regulatory development

- The CB Trial Tariff can be effective reducing the peak demand of the community in the critical instances i.e., evening peak. Nevertheless, it cannot ensure that the BESS dispatch does not increase the community peak demand in the remaining instances. Which is relevant as peak demand conditions can be expected at other instances if the centralized BESS is providing wholesale market arbitrage.
- Additionally, if peak demand conditions within the community occurred outside the window of the CB trial tariff charging imports, the BESS will not be incentivized to reduce the aggregate community peak demand.
- If the BESS is subject to wholesale market prices, the HV network tariff prices on community energy imports are orders of magnitude lower than wholesale market prices. Therefore, these are ineffective in shifting the BESS dispatch, which prioritizes wholesale market arbitrage.
- The Residential ToU tariff is comprised of prices that are closer in the order of magnitude of wholesale energy prices. Therefore, it is applied at the community interface, to understand the impact of network charges on usage at community level. Since network charges on usage are applied only for imports, the community operation effectively increases its economic “self-sufficiency”. That is, given there are additional charges when importing energy from the upstream grid, but there are no additional benefits when exporting, the BESS is operated to increase the use of local generation, and during more instances throughout the day the net exchange of the community with the upstream grid is null.
- Community peak demand charges have a material impact in the BESS dispatch. The BESS co-optimizes the peak demand reduction with wholesale market arbitrage. In turn, the community peak demand is reduced during the different critical instances throughout a day when compared to the remaining scenarios.
- Network tariffs can be comprised of two components i.e., usage and capacity/peak demand. Each charge has a distinct impact on the community operation when applied at community-level. When incorporating both charges, minimal synergies for the community arise in network

arbitrage i.e., the network charges on peak demand for the community are virtually the same if it is the only component of the tariff or if there is a usage component as well. Therefore, network tariffs need to be carefully designed with the inclusion of both components to avoid an increase in costs for the community. Operationally, when having both components in the network tariff the community imports and exports are similar to the only usage case, except during the peak demand conditions, in which the BESS is dispatched to reduce those critical peak conditions.

- A new community network tariff can be designed to be applied at the interface of the community with the upstream grid, while being reflective of the costs of the MV and LV network. Another avenue is to use existing HV customer tariffs while implementing a LUoS inside the community, which can ensure the MV and LV network costs are recovered.

3.4 Reliability

A key aspect to consider when implementing a microgrid is its ability to supply local energy during extreme weather events, such as bushfires, where the town might be disconnected from the upstream grid. With adequate emergency responses, centralized DER can reduce the energy not served during these extreme weather events, resulting in improved reliability. Given that the impact of bushfires is highly uncertain, the reliability benefit has been quantified in Project 7 [6] and Project 8 [1] using the expected energy not served (EENS) which accounts for uncertainty, and it is measured in MWh/year. Project 8 performed a study analysing the reduction of EENS during bushfires of different durations, comparing the case in which the centralized DER have an emergency response to supply local energy demanded during the event and the case in which this emergency response is not implemented. For a case of a centralized BESS of 285kWh (which would result in equivalent results to the 185kWh centralized BESS studied in this report) the results are presented in Figure 24.

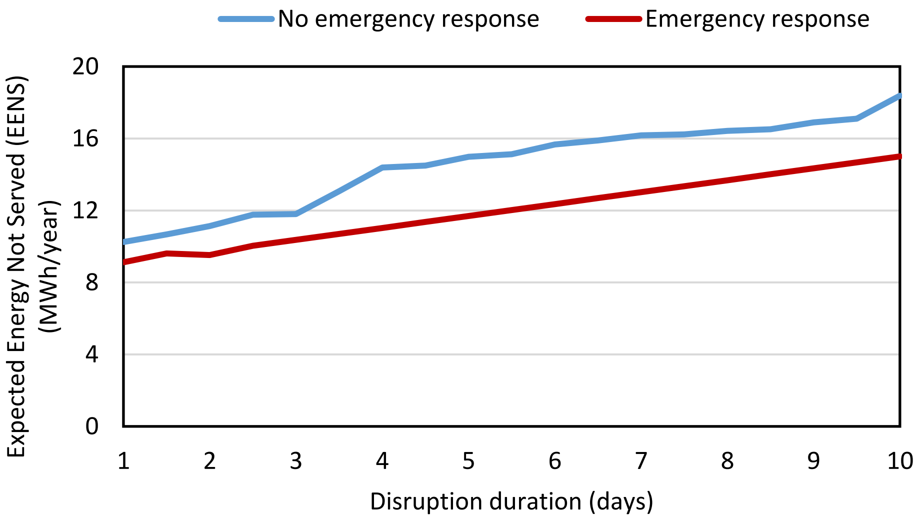

Figure 24. EENS (MWh/year) in Tarnagulla, with and without the emergency response from the centralized BESS for different bushfire durations

The results of EENS can be transformed in economic terms by using the value of customer reliability (VCR), which in previous projects has been considered as $27.45/kWh, following Powercor guidelines. VCR indicates the value customers place in having reliable electricity, and when energy is not supplied, it is used to estimate the cost for the DNSP, often used to identify the right level of investment in network infrastructure. In this sense, the centralized BESS can provide value for customers by reducing the EENS during extreme weather events and reduce costs for the DNSP. Since EENS is measured in MWh/year, the economic results presented in Figure 25 are in $/year. While the value provided is non-linear as the bushfire duration increases, the results indicate there is significant value in utilizing the BESS emergency response during extreme weather events. Given that shorter bushfire durations are more likely than longer bushfire durations, and given the highly uncertain nature of these events, a 1.5 day bushfire duration can be used as a conservative estimate of the value the centralized BESS with emergency response during these events can provide, which is equal to $30,000.

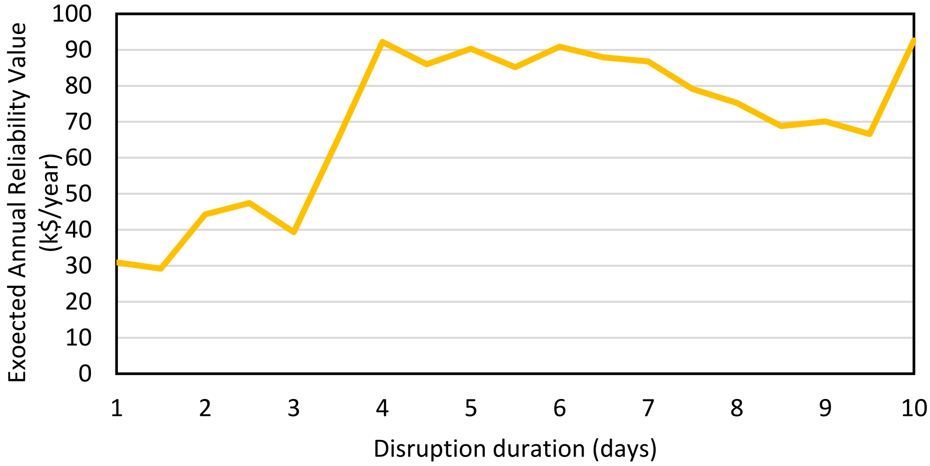

Figure 25. Estimated value of the centralized BESS providing emergency response for different bushfire durations

The recommended investment results for Donald in Project 8 significantly differ from the installed BESS studied in this report. In this report, it was prioritized to present equivalent conditions in both towns to understand the differences arising from a larger community in the different regulatory scenarios and frameworks. Therefore, for each community BESS capacity installed was selected to be equal to current PV installed in each community. However, Project 8 displayed considerably higher required investment in BESS, and there are no reliability results available using the BESS installed equal to 775kWh or a similar capacity. Nevertheless, it must be noted that Project 8 identified that Donald presented further synergies between the optimal investment for “normal operation” and during extreme weather events. It overall displayed that using the centralized DER to provide reliability benefits during extreme weather events on top of accessing services and markets significantly increased the value of the project in Donald.

Implications for regulatory development

- Increased reliability from the centralized DER can provide significant value to the community. Therefore it is highly relevant that this value stream is included, and there exists a regulatory framework by which DER have an emergency response to supply the local demand during these events.

3.5 Provision of network services to the upstream grid

3.5.1 Congestion management service to upstream grid via demand response

The following scenarios focus on the case of centralized BESS only providing energy services via wholesale energy market participation. The centralized BESS is operated in coordination with all PV and demand in the community to minimise the total costs of the community subject to wholesale market prices. The different scenarios correspond to the existence of a demand response (DR) service that allows the centralized BESS to provide congestion management service to the upstream grid.

- **No demand response (DR):** the whole community imports and exports are subject to wholesale market prices, charged at the interface of the community with the upstream grid.

The centralized BESS is operated in coordination with all PV and demand in the community to minimise the total costs of the community subject to wholesale market prices. Network charges are applied at MV/LV transformer level.

- **Demand response (DR) service:** as above, but with the inclusion of a DR service the BESS can provide, with the techno-economic attributes presented in Table 8. DR delivery is included in the representative summer week.

Figure 26 compares the economic position of the community of the two scenarios presented. In the first scenario there is no congestion management service to provide to the upstream grid, whereas in the second scenario the BESS participates in DR services. The DR revenues are factored to represent the equivalent revenues during the week, whereas DR capacity is a single payment for the available capacity the BESS offers for the whole duration of the service (e.g., the whole summer) and DR delivery are the payments when the BESS responds to the DR service, assumed to occur three times during the summer. The results display that DR can potentially be a relevant source of income for the community, and should be an option to explore if the DNSP could benefit from DR to reduce peak demand conditions.

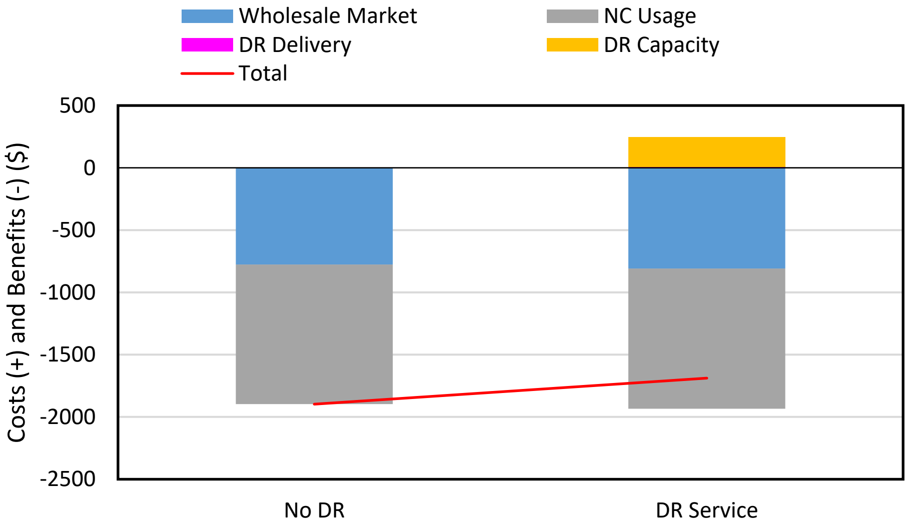

Figure 26. Comparison of the two scenarios for the provision of congestion management service during the representative summer week in Tarnagulla

The total result of congestion management service is provided below, in which the BESS provides 110 kW capacity, which means at any point during the summer it must be able to discharge or reduce its charging a total of 110kWh for one hour duration of the DR event. Considering three events are called it delivers 330kWh of DR.

Table 14. Tarnagulla Demand Response (DR) techno-economic results.

Network Tariff	DR Availability	DR Delivery
Quantity	110 kW	330 kWh
Annual Revenues	$2860	$82.5

Equivalent results are presented for Donald in Figure 27 and Table 15, with equivalent conclusions. As expected, a larger centralized BESS will be able to provide further DR, further reduce congestion management and increase revenues.

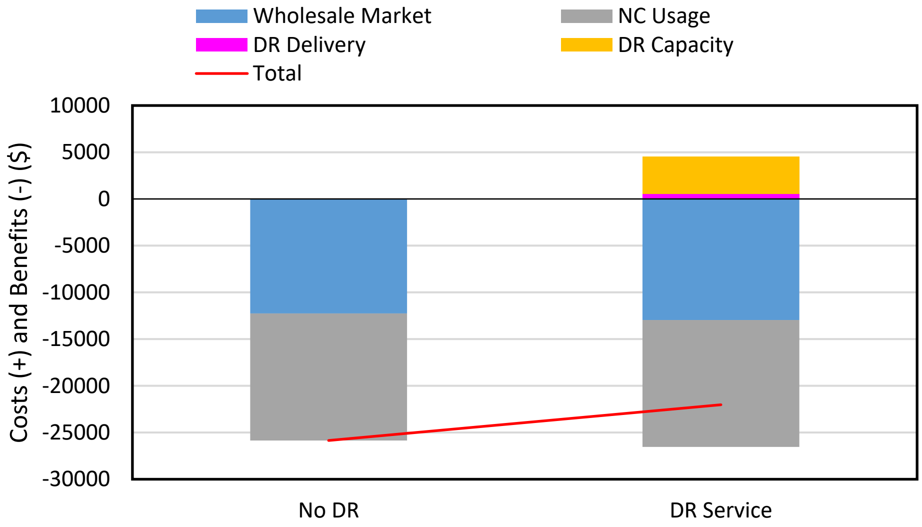

Figure 27. Comparison of the two scenarios for the provision of congestion management service during the representative summer week in Donald

Table 15. Donald Demand Response (DR) techno-economic results.

Network Tariff	**DR Availability**	**DR Delivery**
Quantity	460 kW	1.38 MWh
Annual Revenues	$11983	$1035

3.5.2 Voltage management service to upstream grid

Currently there is not a general voltage management service in place. Nevertheless, in previous projects it has been indicated that establishing a microgrid could result in voltage issues in the upstream network [6]. To demonstrate the ability of the centralized BESS to provide voltage management to the upstream network the following scenarios are generated:

- **No voltage management upstream:** the whole community imports and exports are subject to wholesale market prices, charged at the interface of the community with the upstream grid. The centralized BESS is operated in coordination with all PV and demand in the community to minimise the total costs of the community subject to wholesale market prices. Network charges are applied at MV/LV transformer level.
- **Voltage management upstream:** as above, but with the inclusion of a voltage management service where the community imports and exports of reactive power are subject to a price signal. This price signal is based on the United Kingdom reactive power support service is generated equal to $5.6/MVArh. To promote reactive power absorption during high solar times (potentially reducing voltage rise issues) the price signal is negative, and during the evening the price signal is positive to promote injection of reactive power to the upstream grid (potentially reducing voltage drop issues).

Figure 28 and Figure 29 presents the net economic position of Tarnagulla and Donald in the two different scenarios. The results display that with minimal impact on its performance on wholesale energy market, the centralized BESS can provide significant voltage management to the upstream network. This in turn improves the community economic position. This is further supported by Figure

30, in which the price signals on reactive power are presented along with the community reactive power imports and exports for Tarnagulla. Overall, the centralized BESS can have a material impact on the community total reactive power exchange with the upstream grid if provided with appropriate price signals. It must be noted the objective of the proposed study is to demonstrate the capability for the community to provide upstream voltage management and to understand its economic potential. Further study is required to analyse the system-level impact of the provision of voltage management services.

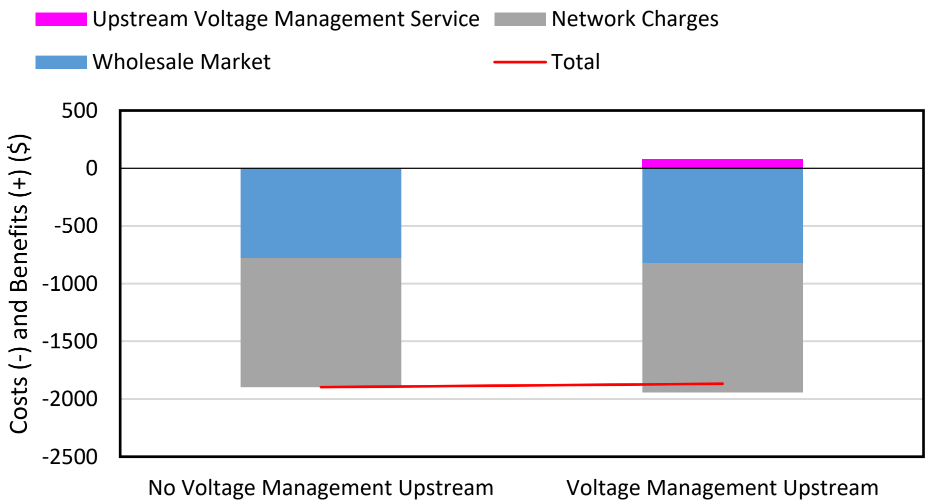

Figure 28. Comparison of the two scenarios for the provision of voltage management service during the representative summer week in Tarnagulla

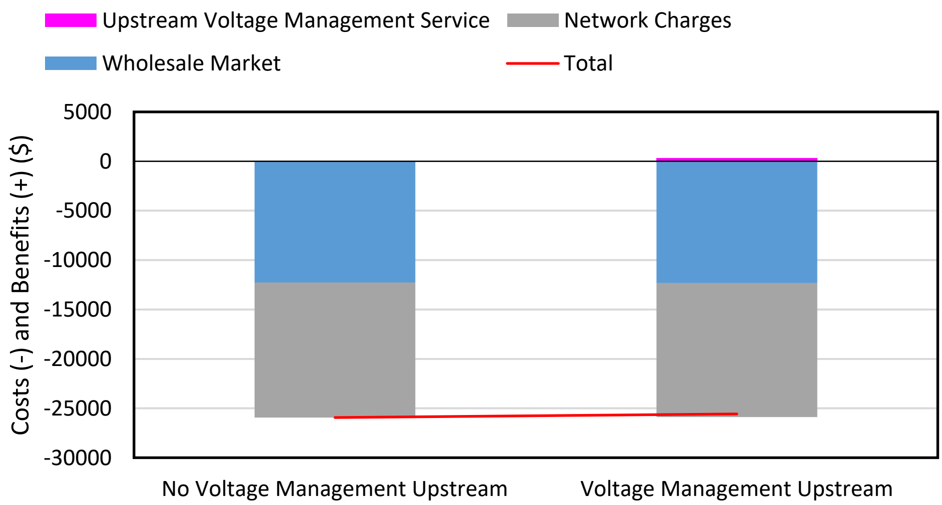

Figure 29. Comparison of the two scenarios for the provision of voltage management service during the representative summer week in Donald

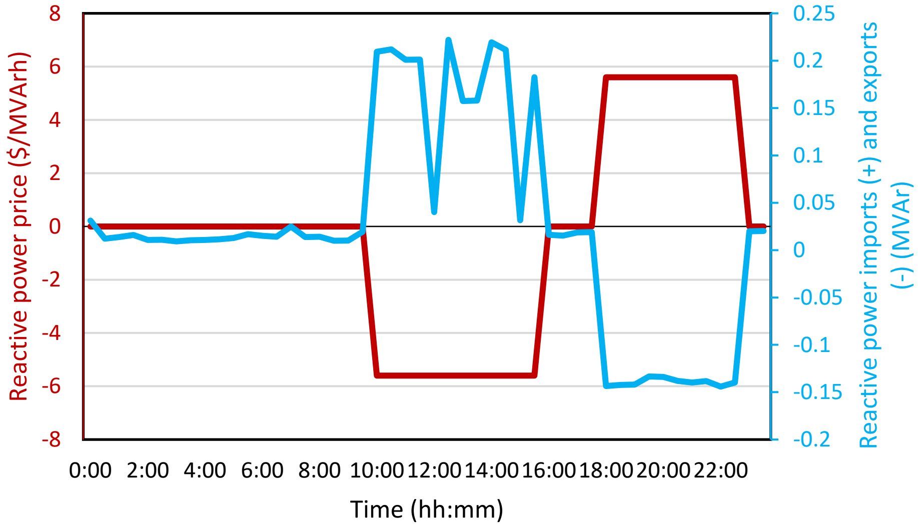

Figure 30. Tarnagulla example of reactive power price signals for the community to exchange reactive power with the upstream grid and reactive imports and exports of the community with the upstream grid

Implications for regulatory development

- The centralized DER can be operated to provide valuable network services (i.e., congestion and voltage management) to the upstream grid. Additionally, if these network services are required, significant revenues can be accrued by the community, improving its net position.
- Further studies are required to better understand what network services are required in the upstream grid. This will allow to provide more accurate estimates of economic impact for the community. Nevertheless, the potential for a community with centralized DER to provide upstream network services should not be disregarded, as these can be significant, and when considered within DNSP planning methodologies can potentially result in avoided network reinforcement.

4 References

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