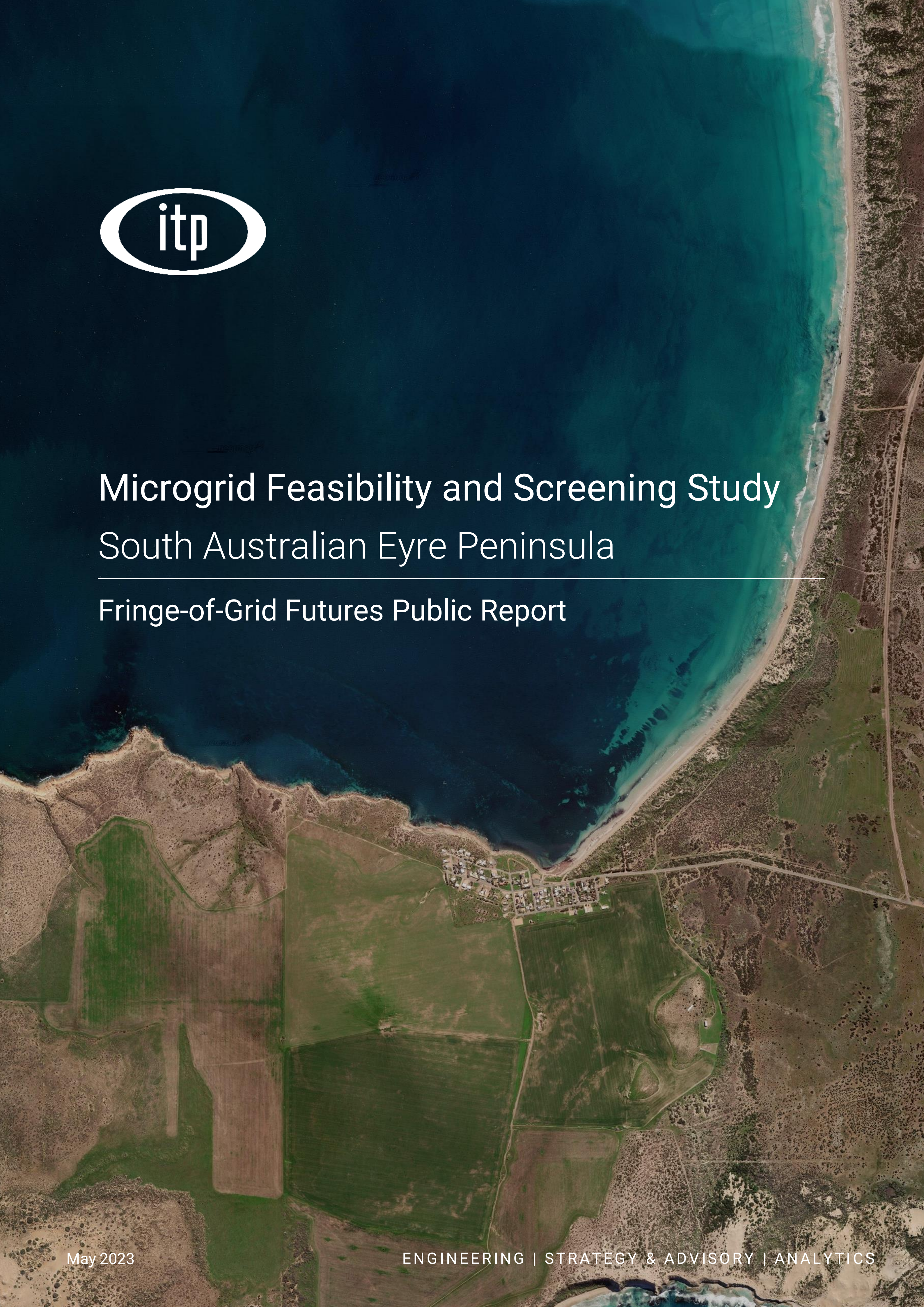

Microgrid Feasibility and Screening Study

South Australian Eyre Peninsula

Fringe-of-Grid Futures Public Report

May 2023

ENGINEERING | STRATEGY & ADVISORY | ANALYTICS

About ITP Renewables

ITP Renewables (ITP) is a global leader in renewable energy engineering, strategy, compliance, and energy sector analytics. Our technical and policy expertise spans the breadth of renewable energy, energy storage, energy efficiency and smart integration technologies. Our range of services cover the entire spectrum of the energy sector value chain, from technology assessment and market forecasting right through to project operations, maintenance, and quality assurance.

We were established in 2003 and operate out of offices in Canberra (Head Office), Sydney, North Coast NSW, Adelaide and Auckland, New Zealand. We are part of the international ITPEnergised Group, one of the world's largest, most experienced, and respected specialist engineering consultancies focusing on renewable energy, energy efficiency, and carbon markets. The Group has undertaken over 2,000 contracts in energy projects encompassing over 150 countries since it was formed in 1981.

Our regular clients include governments, energy utilities, financial institutions, international development donor agencies, project developers and investors, the R&D community, and private firms.

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About this Report

The **Fringe-of-Grid Futures South Australia Eyre Peninsula** project was awarded $1.08 million from Round Two of the Australian Government's Regional and Remote Communities Reliability Fund in December 2021 to examine the potential for the electricity distribution network on the Eyre Peninsula to transition to renewable energy microgrids.

The project undertaken by a consortium of ITP, SA Power Networks (SAPN), ener-G, UniSA and Regional Development Australia Eyre Peninsula (RDAEP) comprised of the following:

- **Microgrid Feasibility Studies:** Technical and economic feasibility assessments for microgrids to improve the reliability of power supply at three separate localities of Kimba, Koonibba, and Sceale Bay in the Eyre Peninsula. Each of the studies considered the regulatory frameworks for microgrid implementation, business models for ownership/operation, concept design, a 25-year financial cost benefit analysis of a project.
- **A Microgrid and Individual Power System (IPS) Screening Study** to assess the financial implications of disconnecting portions of the Eyre Peninsula electricity distribution network and replacing them with microgrids or individual power system systems. The Screening Study was undertaken in parallel with the feasibility studies, with the results of the feasibility studies to inform the model and validate the results.

South Australia's electricity distribution provider SA Power Networks (SAPN) has collaborated extensively on the analysis for the project. SAPN provided a rich GIS database of distribution assets across the Eyre Peninsula, load data for whole of the Eyre Peninsula, and extensive data from its risk cost modelling tools covering bushfire, customer reliability, safety, environmental, and financial consequences. As part of the project, SAPN substantially modified existing methodologies for attributing bushfire and customers reliability risks to distribution assets, to facilitate ITP's analysis in both the Feasibility Studies, and the Screening Study.

The focus of the project has been on improving the reliability of power supply to Kimba, Koonibba, and Sceale Bay using distributed energy resources (DER), to reduce operating costs for SAPN and increase local renewable energy supply.

Detailed Commercial-In-Confidence versions of the three feasibility studies and the screening study methodology and results were provided to SAPN in May 2023.

This Public Report summarises the overall findings from the project without confidential information and is for public dissemination.

Abbreviations

AC	Alternating current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AEO	Annual Energy Outlook, prepared by the US EIA
AER	Australian Energy Regulator
AIP	Australian Institute of Petroleum
APVI	Australian Photovoltaics Institute
ARENA	Australian Renewable Energy Agency
AUD	Australian Dollar
BESS	Battery energy storage system
CAPEX	Capital expenditure
CSIRO	Commonwealth Science and Industrial Research Organisation
CT	Current transformer
DAPR	Distribution Annual Planning Report
DC	Direct current
DER	Distributed energy resources
DISER	Department of Industry, Science, Energy, and Resources
DNSP	Distribution network service provider
DRED	Demand response enabled devices
DSP	Demand side participation
DUOS	Distribution use of service
EIA	US Energy Information Administration
ENO	Embedded network operator
EPC	Engineering, procurement, and construction
ESS	Energy storage system
EV	Electric vehicle
FCAS	Frequency control ancillary services
FiT	Feed-in-tariff
FOB	Free onboard
FTC	Fuel tax credits
FTE	Full time equivalent
GDP	Gross domestic product
GIS	Geographic information system
HV	High voltage
IEA	International Energy Agency
IPS	Individual Power System
ISP	Integrated System Plan, prepared by AEMO
ITP	IT Power (Australia) Pty Ltd
kV	Kilovolt, unit of electrical potential
kVA	Kilovolt-ampere, unit of apparent power
kVAr	Kilovolt-ampere reactive, unit of reactive power
kW	Kilowatt, unit of power
kWh	Kilowatt-hour, unit of energy (1 kW generated/used for 1 hour)
kWp	Kilowatt-peak, unit of power for PV panels tested at STC
LCOE	Levelised cost of energy
LET	Local energy trading
LGC	Large-scale Generation Certificates
LUOS	Local use of system
MVA	Megavolt-ampere, equivalent to 1,000 kVA
MW	Megawatt, equivalent to 1,000 kW
MWh	Megawatt-hour, equivalent to 1,000 kWh
MWp	Megawatt-peak, equivalent to 1,000 kWp
NEM	National Electricity Market
NEMDE	NEM dispatch engine

NER	National Electricity Rules
NPC	Net present cost
NPV	Net present value
NREL	US National Renewable Energy Laboratory
NSP	Network service provided
NUOS	Network use of service
OPEX	Operating expenditure
O&M	Operations and maintenance
POE	Probability of exceedance
PPA	Power purchase agreement
PV	Photovoltaic
RDAEP	Regional Development Australia, Eyre Peninsula
RE	Renewable energy
RRCRF	Regional and Remote Communities Reliability Fund
SAPN	SA Power Networks
SAPS	Standalone power system
STC	Standard Test Conditions for PV panels
SWER	Single wire earth return
tCO2-e	Tonnes of CO2 equivalent
TGP	Terminal gate price
TNSP	Transmission network service provider
TOU	Time of use
TUOS	Transmission use of service
TX	Transformer
ULP	Unleaded petrol
UniSA	University of South Australia
UPS	Uninterruptible power supply
USD	US dollar
VCR	Value of customer reliability
VPP	Virtual power plant
VT	Voltage transformer
ZS	Zone substation

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Executive Summary

The Eyre Peninsula is the westernmost part of the National Electricity Market (NEM) with distributed and small communities in remote townships and isolated properties. These communities play a significant role in Australia's tourism, agriculture, manufacturing, and export sectors, but have been disproportionately impacted by issues of electricity affordability and reliability.

This Microgrid Feasibility and Screening Study was made possible with funding from Round Two of the Australian Government's Regional and Remote Communities Reliability Fund (RRCRF). The RRCRF was established in October 2019. Its purpose is to support regional and remote communities in determining the cost-effectiveness of various options, including replacing, upgrading, or supplementing microgrids, as well as upgrading existing off-grid and fringe-of-grid supply using microgrids or other new energy technologies.

The intended outcomes of the RRCRF are:

- Viable projects attract funding to support scale-up / implementation of microgrid systems in regional and remote communities.
- Increased human capital (skills/knowledge) in the design and deployment of microgrids.
- Demonstrated commerciality and/or reliability and security benefits of deploying and upgrading microgrids.
- Reduced barriers to microgrid uptake in remote and regional communities.
- Increased dissemination of technology and/or project knowledge regarding the deployment and upgrading of microgrids.

ITP Renewables was commissioned to perform detailed microgrid feasibility studies at three locations in the Eyre Peninsula; Kimba, Koonibba, and Sceale Bay, and to develop a method to screen for the potential of microgrids and individual power systems to reduce costs across the entire Eyre Peninsula distribution network. Kimba and Koonibba were selected by RDAEP as locations of interest based on community motivation. The selection of Sceale Bay as the third location for feasibility study was informed by the distribution network operator, SA Power Networks (SAPN)'s visual assessment of customers at the end of long spur lines, ITP assessment of maintenance costs and SAPN consideration of bushfire risk and corrosion risk.

The current supply to Kimba, Koonibba, and Sceale Bay is via the interconnected grid, and the feasibility studies consider the option of adding microgrid capability to enable occasional islanding of these towns and fulfilment of local electricity demand with local supply. A microgrid would allow portions of the upstream network to be de-energised on days of extreme or catastrophic bush fire risk, minimise outages caused by upstream faults, and reduce carbon emissions attributable to grid imports. Improved reliability of electricity supply would reduce loss of services, supplies, perishable stock, creating a positive impact on health services, education services, and local businesses.

The microgrid and individual power system (IPS) screening study assesses the cost implications of modifying the existing electricity distribution network with microgrids or individual power system options across the Eyre Peninsula. To achieve this, it is necessary to measure whether the distribution network, a microgrid, or IPS are lower cost for any combination of adjacent customers, at any location within the Eyre Peninsula distribution network. Battery energy storage system (BESS) cost sensitivity analysis also provides insight in to when certain network modifications become feasible if prices change.

These variables create a very large number of possible scenarios to consider, and the results of this study allow these scenarios to be ranked to inform infrastructure planning.

Findings

Regulatory Framework

Microgrids, as defined by the Australian Energy Market Commission (AEMC), are always isolated from the interconnected grid. However, the focus of this report is on sections of the interconnected grid that may sometimes be islanded, and so operate as a microgrid intermittently. Intermittent microgrids have not been defined as a possible model of electricity supply for customers under the National Electricity Rules (NER). The Australian Energy Regulator (AER) has identified market settlement, customer retail tariffs, responsibility/liability for managing supply and demand, protection and power quality, and retailer-related mechanisms as some of the regulatory issues requiring further development to enable complete governance of intermittent microgrids.

If islanded operation is for short durations, the AER considers that the regulatory and financial issues arising are immaterial.

Business Models

Kimba and Sceale Bay

There are two options for ownership of assets that enable islanding. In both, SAPN retains ownership of the local network and customers retain their choice of retailer.

The first option is for SAPN to own and operate any in-front-of-meter generation/ storage. The assets can be used to provide network support but cannot participate in competitive markets such as wholesale spot and frequency control and ancillary services (FCAS), though it may be possible for SAPN to allow a 3rd party to lease and operate it within limits set by SAPN under an AER waiver. The assets could form part of SAPN's Regulated Asset Base (RAB) if approved by the AER, allowing capital and operating costs to be recovered from all SA customers in the NEM.

The second option is for a 3rd party to own and operate any in-front-of-meter generation/storage assets. The capital and operating costs would be serviced by revenues from spot and FCAS markets and potentially a bilateral contract with SAPN to provide network support services (e.g. islanding).

Koonibba

There is anecdotal evidence that the community is interested in an alternative power supply arrangement. Community leaders have suggested that a communal model of procuring power may be preferable to individual retail contracts for each dwelling. This communal model would involve a community management corporation. Using grant funding, the community entity would own the central generation/ storage assets (e.g. by engaging a 3rd party developer who would develop and construct in-front-of-meter generation/storage assets on behalf of the community entity). Households would retain their existing retailer, and the community entity, using revenues from the generation/storage assets, would i) take on financial responsibility for household electricity bills (without becoming their retailer), or ii) pay each household a quarterly dividend that could be used to offset their electricity bill costs, or iii) establish/manage a community fund for other electricity cost reduction measures such as subsidising more efficient appliances.

Concept Design

Kimba

This study found that a 4.55 MWp solar PV system coupled with a 4.5 MW/18 MWh BESS would provide sufficient generation to meet 93% of local demand in island mode in year 1 (2025), falling to 81% after 25 years (owing to load growth and PV/BESS degradation). Given that less than 100% of demand would be served, the community would be required to engage in a small amount of “demand response” during islanding events to conserve energy. Alternatively, 2 MW of diesel generation could be installed in parallel to increase demand coverage to 100%.

Koonibba

This study found that a 585 kWp solar PV system coupled with a 425 kW/1,700 kWh BESS would provide sufficient generation to meet 98% of local demand in island mode in year 1 (2025), falling to 92% after 25 years (owing to load growth and PV/BESS degradation). Given that less than 100% of demand would be served, the community would be required to engage in a small amount of “demand response” during islanding events to conserve energy. Alternatively, 300 kW of diesel generation could be installed in parallel to increase demand coverage to 100%.

Sceale Bay

This study found that a 260 kWp solar PV system coupled with a 300 kW/630 kWh BESS would provide sufficient generation to meet 92% of local demand in island mode in year 1 (2025), falling to 71% after 10 years (owing to load growth and PV/BESS degradation). Given that less than 100% of demand would be served, the community would be required to engage in a small amount of “demand response” during islanding events to conserve energy. Alternatively, 120 kW of diesel generation could be installed in parallel to increase demand coverage to 100%.

Financial Results

The results suggest that these projects will not pay back over a 25-year lifetime, without additional subsidy. There are several factors that contribute to this result, including:

1. The size of each project is insufficient to achieve the economies-of-scale that larger PV and BESS projects competing in the same markets can achieve
2. The export constraint imposed by the local distribution network results in curtailment
3. Unlike larger BESS located near transmission substations, these BESS systems will be unable to access all FCAS markets and associated revenues

The indirect financial benefits to SAPN associated with each project proceeding include the reduced bushfire risk and improved reliability for their customers. However, the magnitude of these benefits is not sufficient to offset the projected financial losses of each project, suggesting it is unlikely that SAPN could offer a sufficient incentive to attract a project developer.

Each project is expected to avoid a small volume of emissions over its lifetime. However, even at a high carbon price, this is insufficient to materially impact the economic case.

Microgrid and Individual Power System Screening

This study found that 204 connection points (mostly homes and small businesses) on the Eyre Peninsula distribution network have the potential for implementation of IPS, allowing for the decommission of existing network assets. 162 connection points have the potential to be powered by a microgrid. Microgrids use existing network assets, so poles, wires, and other components would not be decommissioned when implementing microgrids at these locations.

A BESS Cost Sensitivity analysis shows that for both microgrid and IPS, substation zones SSD188 Port Lincoln Terminal and SSD269 Darke Peake are good candidates to re-screen in the future if BESS prices reduce below 70% of current prices. This study showed that there are no additional zones to consider for future disconnection.

A screening tool verification study shows that the largest contributing factors towards a positive financial return for IPS and microgrid implementation are the large VCR and bushfire risk associated with network assets such as high-voltage feeders, in combination with a low system cost for a given modification.

The total annual return to SAPN for all identified network modifications and all zones is $414,456. The total Net Present Value (NPV) over the lifetime of these systems would be approximately $7.3 million, with a discount rate of 2.9%.

Background

The Eyre Peninsula is the westernmost part of the National Electricity Market (NEM) with distributed and small communities in remote townships and isolated properties. These communities play a significant role in Australia's tourism, agriculture, manufacturing, and export sectors, but have been disproportionately impacted by issues of electricity reliability, cost, and security of supply. The transition to renewable energy microgrids in the region could provide more reliable power.

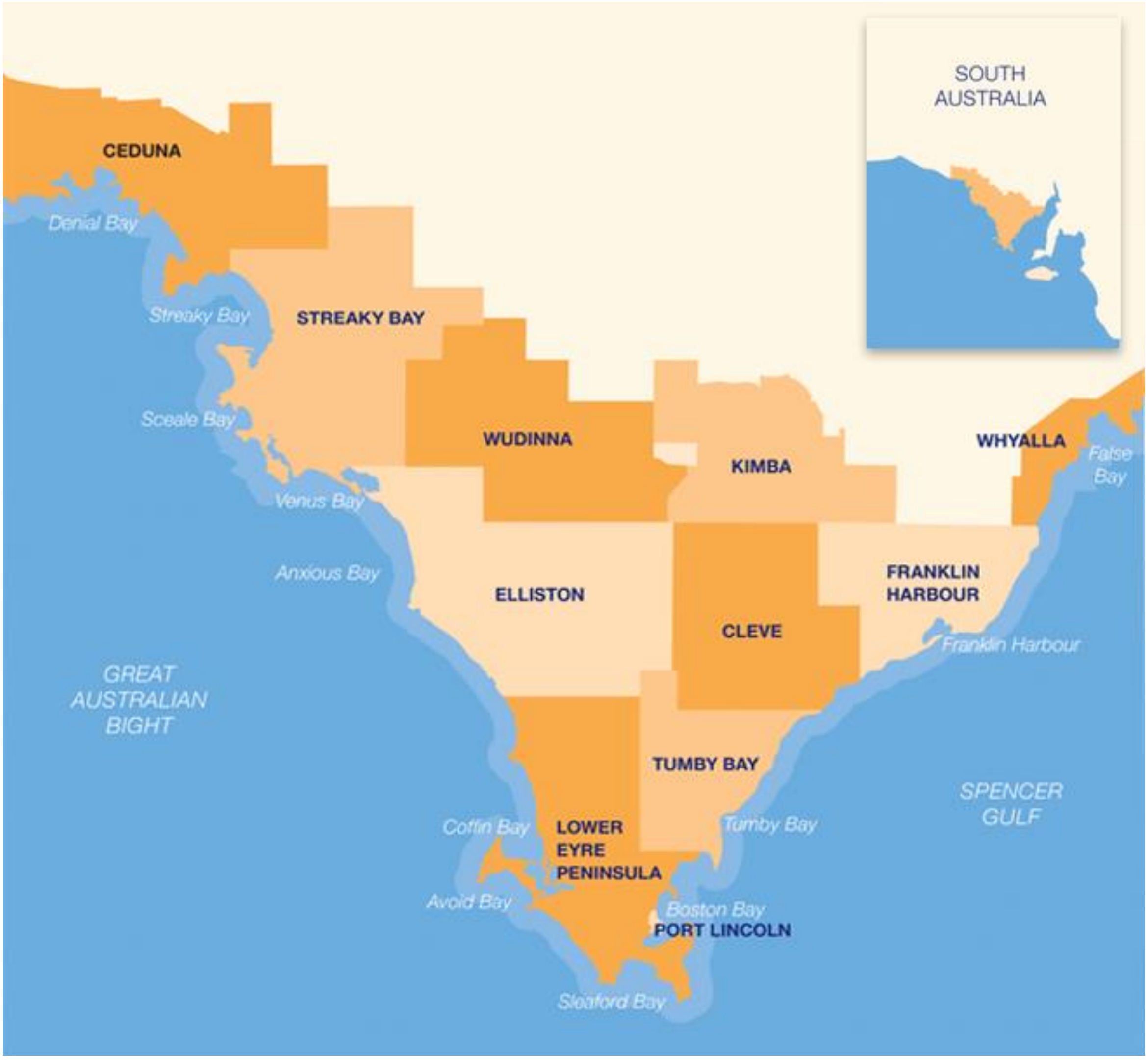


Figure 1: Map of Eyre Peninsula Local Government Areas[1]

Kimba is a rural town located on the Eyre Highway approximately 150 km southwest of Port Augusta as shown in Figure 2. It is the administrative centre for the District Council of Kimba, and the eastern gateway to the Gawler Range. According to the 2021 Census, the

[1] Eyre Peninsula Local Government Association

town had a population of 608 people, with 1,037 living in the District Council Local Government Area (LGA).[2] The top employment industries are sheep and cattle grazing, followed by grain growing, which directly employed 40% of workers. Median household incomes were slightly higher than the rest of SA, but lower than the national median.[3]

Koonibba is a small Aboriginal settlement located in the western portion of the Eyre Peninsula about 40 km north-west of Ceduna as shown in Figure 2. The community is located within the District Council of Ceduna area and had a population of 125 according to the 2021 census.[4] Koonibba is situated near the far western end of SAPN's network.

Sceale Bay is a small town located on the west coast of the Eyre Peninsula, in Streaky Bay District Council about 30 km south of Streaky Bay as shown in Figure 2. The town had 55 residents according to the 2021 Census,[5] although there are many holiday homes, and tourist accommodation which see the population fluctuate by season.

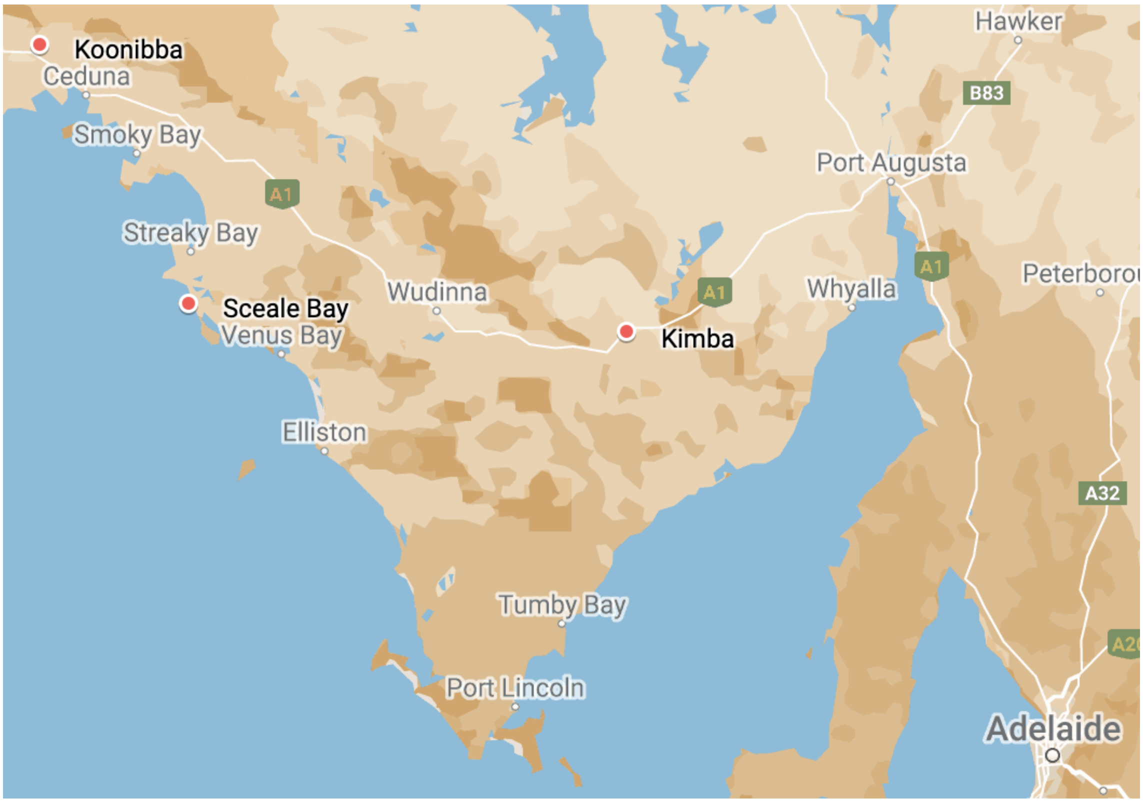


Figure 2: Location of Kimba, Koonibba, and Sceale Bay in the Eyre Peninsula

Regional and Remote Communities Reliability Fund

The studies under the Fringe-of-Grid Futures South Australia Eyre Peninsula project were made possible with funding from Round Two of the Australian Government's Regional and Remote Communities Reliability Fund (RRCRF). The RRCRF was established in October 2019

[2] https://abs.gov.au/census/find-census-data/quickstats/2021/LGA43220
[3] RDAEP (2022), *District Council of Kimba. Economic Profile*, https://economy.id.com.au/rda-eyre-peninsula/
[4] https://abs.gov.au/census/find-census-data/quickstats/2021/ILOC40300102
[5] https://abs.gov.au/census/find-census-data/quickstats/2021/SAL41308

to support regional and remote communities to investigate whether replacing, upgrading, or supplementing a microgrid or upgrading existing off-grid and fringe-of-grid supply with micro grids or related new energy technologies would be cost effective.

The intended outcomes of the RRCRF are:

- Viable projects attract funding to support scale-up / implementation of microgrid systems in regional and remote communities.
- Increased human capital (skills/knowledge) in the design and deployment of microgrids.
- Demonstrated commerciality and/or reliability and security benefits of deploying and upgrading microgrids.
- Reduced barriers to microgrid uptake in remote and regional communities.
- Increased dissemination of technology and/or project knowledge regarding the deployment and upgrading of microgrids.

Purpose of these studies

Microgrid Feasibility

The microgrid feasibility study focuses on improving the reliability of power supply to Kimba, Koonibba, and Sceale Bay using distributed energy resources (DER). This includes local power generation systems such as solar photovoltaics (PV), either behind-the-meter or metered separately, in conjunction with battery energy storage systems (BESS), potentially with diesel backup. This study assesses the regulatory environment, social, cultural, and economic factors, barriers to implementation, and potential funding sources.

The key outcomes this study aims to deliver are:

- Improve the reliability of power supply to Kimba, Koonibba, and Sceale Bay
- Reduce operating costs for SAPN
- Increase local renewable energy supply

An intermittent microgrid is one option for addressing these concerns and is considered for all three locations. A privately-owned embedded network for any of them is not likely and is not considered in this report.

ITP also considered alternative models including BESS-only systems designed to reduce outage time caused by upstream faults, and a combination of isolated microgrids for the townships, and IPS for outlying customers. These options are not explored in detail in this report as our analysis found that they are not compelling options in these locations. Nevertheless, isolated microgrids and IPS may have potential in other parts of the Eyre Peninsula, and BESS-only systems may have potential in parts of the network that experience more frequent, short duration outages.

Microgrid and Individual Power System Screening

The microgrid and individual power system (IPS) screening study was developed to assess the financial implications of modifying the existing electricity distribution network with microgrids or individual power system options across the Eyre Peninsula. To achieve this, it is necessary to measure whether the distribution network, a microgrid, or IPS are more favourable for any combination of adjacent customers, at any location within the Eyre Peninsula distribution network. BESS cost sensitivity analysis will also provide insight in to when certain network modifications become feasible if prices change.

These variables create a very large number of possible scenarios to consider, and the measurement defined in this study allows all these scenarios to be ranked according to chosen decision metrics, to prioritise infrastructure planning.

Definitions

This study uses the Australian Energy Market Commission (AEMC) definitions for modes of electricity supply:[6]

- Supply via the interconnected grid, referred to as 'standard supply'.
- Supply via an embedded network, which in turn is connected to the interconnected grid.
- Supply via a microgrid isolated from the interconnected grid.
- Supply via an individual power system (IPS), which only provides electricity to the customer in question.

We also use their definitions for Stand-alone Power Systems (SAPS), microgrids, and Individual Power Systems (IPS).

SAPS

An electricity supply arrangement that is not physically connected (directly or indirectly) to the national grid can be referred to as a stand-alone power system (SAPS). Microgrids and individual power systems are both a form of stand-alone power system.

Microgrid

A microgrid is a SAPS that generates and supplies electricity to multiple customers. This could include anything from a large town to two farms connected to each other. Power may

[6] *Updating the regulatory frameworks for distributor-led stand-alone power systems,* Australian Energy Market Operator 2020, https://www.aemc.gov.au/sites/default/files/documents/updating_the_regulatory_frameworks_for_distributor-led_stand-alone_power_systems_final_report_28_may_2020.pdf

be supplied by a mix of local generation and storage, possibly combined with behind-the-meter generation and storage. Remote communities, island resorts and remote mining towns are often supplied by microgrids.

Individual power system

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

Embedded network

Microgrids and individual power systems are distinct from embedded networks. While embedded networks supply electricity to customers in a way that is an alternative to standard supply, they remain connected to the national grid (they may or may not have generation within the embedded network). An embedded network is a privately owned, operated, or controlled electricity network, often within the bounds of a commercial or residential building.

Intermittent Microgrid

There are no regulations or AEMC definitions currently covering intermittent microgrids – microgrids that are connected to the national grid but have sufficient energy resources to be self-sufficient in the case of outages. They are, however, an emerging and important occurrence throughout Australia, so we include them in our definitions. These different modes of electricity supply are illustrated in Figure 3.

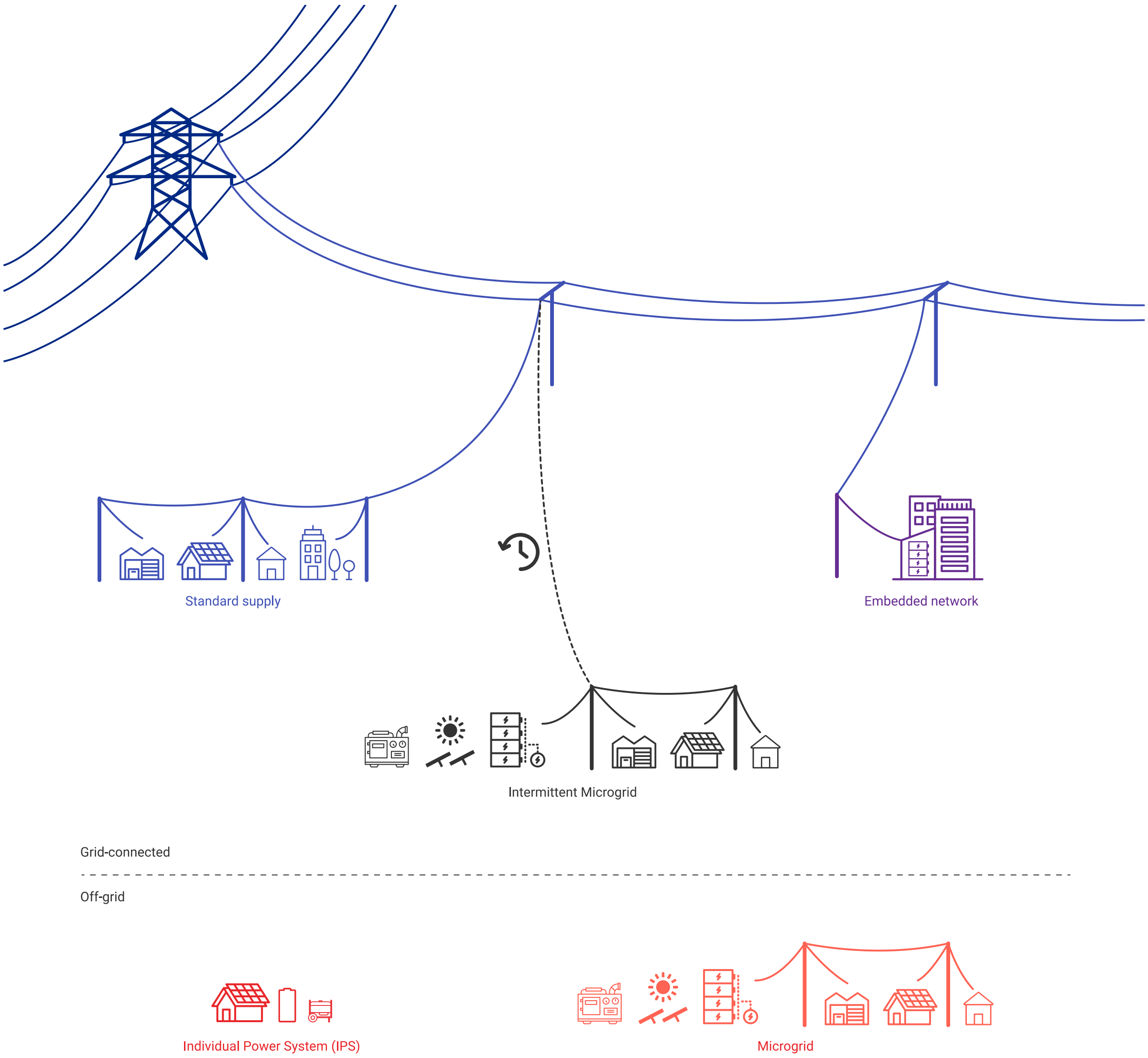


Figure 3: Electricity supply modes

These electricity supply systems can be owned by a DNSP or a private third party, as in Figure 4.

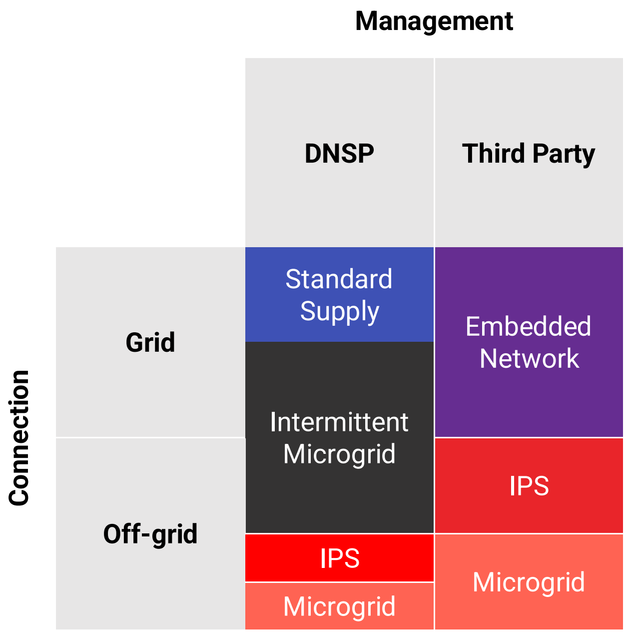
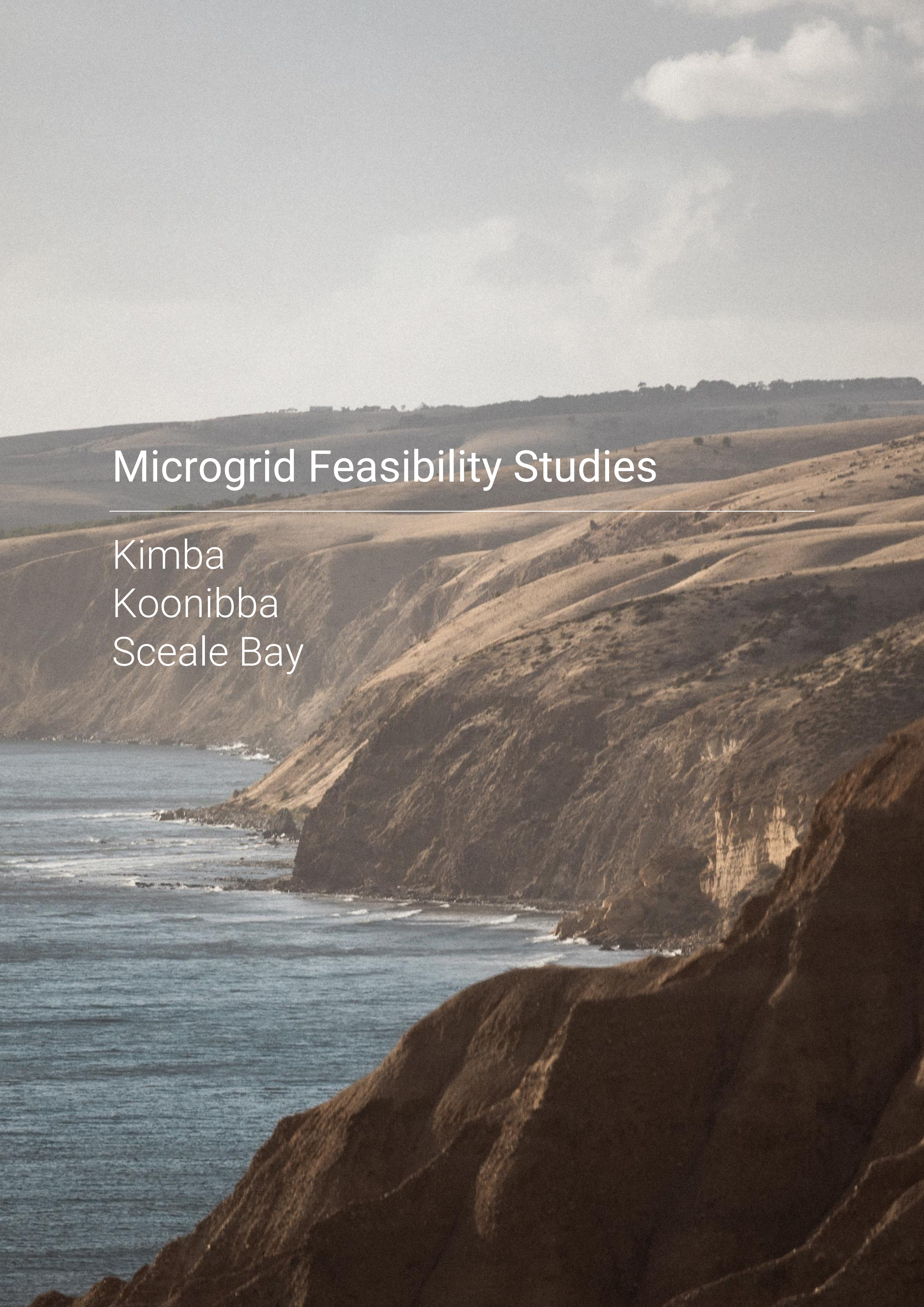


Figure 4: Ownership of different electricity supply modes



Microgrid Feasibility Studies

Kimba
Koonibba
Sceale Bay

1 Regulatory Environment

1.1 Microgrids

Historically, microgrids in Australia have been operated by private and/or state-owned enterprises under a regulatory framework created and implemented by the state government. However, since the release of the AEMC's *'Final Report: Updating the Regulatory Frameworks for Distributor-led Stand-alone Power Systems'*, DNSP-led microgrids are now within the AER's regulatory framework, although this is on an opt-in basis, because the states and the ACT may need to make amendments to their legislation.[7]

Under this framework, SAPN could own generation and storage assets supplying electricity to microgrids provided they receive a waiver from the Australian Energy Regulator (AER). Such a waiver would be granted where it is demonstrated that it would be more efficient, and therefore lower cost, for the DNSP to provide generation services themselves (rather than contracting out to a 3rd party provider). The generation and any storage assets can receive a return from electricity provided by those assets, subject to an individual generation revenue cap linked to each DNSP (which for SAPN is 0.02% of their annual revenue requirement). Where the generation assets are included in the RAB, the payments from AEMO for SAPS generation must also be deducted from the DNSP's revenue allowance.

SAPN would not become the retailer for such microgrids, and customers connected to the microgrid would continue to have a choice of retailer.

1.2 Intermittent Microgrids

Microgrids, as defined by the AEMC, are always isolated from the interconnected grid. However, the focus of this report is on sections of the interconnected grid that may sometimes become islanded (and so operate as a microgrid intermittently). Hereafter, we refer to these sections as **intermittent microgrids**.

Intermittent microgrids are uncommon in the NEM and have been viewed by the AER and AEMC as an anomaly because they operate as microgrids for only short periods of time. One example is Ausnet's Mallacoota Area Grid Storage project that is used to improve both supply reliability and power quality.[8]

Under the AEMC's current definitions, intermittent microgrids are not covered by the NER. However, as more intermittent microgrids are proposed and established, and as islanding occurs for longer periods of time (e.g. when a line may be de-energised for routine maintenance work or when there is risk of a bushfire), the AER and AEMC have shown

[7] Microgrids led by third parties remain exempt.

[8] Ausnet owns a diesel generator and a 1 MWh battery that helps to keep Mallacoota energised when the feeder connecting it to the interconnected grid is down. Ausnet's generation is effectively unmetered as Ausnet is not paid for any electricity generated.

increased interest in how they fit into the regulatory framework. The key issues identified by the AER that need to be addressed for intermittent microgrids to be included under the NER are summarised below.

In addition, although DNSPs may own metered generation assets on microgrids with a waiver from the AER, this is not possible on intermittent microgrids because they are part of the interconnected grid most of the time.

Regardless of how the NER may be altered to allow intermittent microgrids to operate, the requirement for customers to have a choice of retailer from which to buy electricity would still apply for intermittent microgrids.

National Electricity Rules

The main issues that arise because the NER has not been modified for intermittent microgrids in Australia are:

- Market anomalies would arise when islanded because market settlement would be based on customer meter readings that do not account for the fact that the area is disconnected from most of the NEM's generators.
- Customer retail tariffs include components to cover the upstream network costs, losses, and ancillary services payments, none of which should apply when islanding occurs.
- When the microgrid is islanded, it is not clear who will be responsible for matching supply with demand, protection, and power quality, nor who would face any liability claims.
- Application of the Retailer Reliability Obligation (RRO) to intermittent microgrids needs to be clarified in the context of the Reliability and Emergency Reserve Trader (RERT) and the Procurer of Last Resort (POLR).

If the islanding is only for short durations (as for Mallacoota), the AER considers that the distortion is immaterial and so would not merit steps to account for the injected electricity. However, for longer periods (duration unspecified), they would be.

2 Business Models

2.1 Kimba and Sceale Bay

Two business models are considered below. Both assume that SAPN retains ownership of the local network. Both are possible only if islanding is for short durations (as is anticipated), such that the AER considers that any distortions are immaterial.

2.1.1 SAPN ownership of generation/storage assets

In this model, SAPN owns and operates any in-front-of-meter generation/storage assets and uses them to provide network support, which can range from helping to meet demand peaks and voltage control through to maintaining supply during an islanding event. They can only be included in their RAB if the AER considers them to be an efficient investment as an alternative to augmenting the network.

Because they are owned by SAPN, they will not be able to participate in competitive markets such as spot and FCAS. It may be possible for SAPN to own a battery and allow 3rd party lease and operation within limits set by SAPN, but only under an AER waiver. Potential lease payments are difficult to estimate and hence this scenario has not been assessed quantitatively in this report.

2.1.2 Private ownership of generation/storage assets

In this model, a 3rd party owns and operates any in-front-of-meter generation/storage assets. They will be able to participate in spot and FCAS markets and may have a bilateral contract with SAPN to provide network support (e.g. islanding).

Assuming that the intermittent microgrid will be islanded for only short periods of time, there should be no material impact on the financial contracts of any generator connected to it. According to AEMO's market settlement processes, even when islanded, the generator will still be treated as though it is connected to the interconnected grid and so will be paid for all generation through the spot market. Of course, while islanded, the generator will not be able to provide a frequency response to the NEM and hence should not bid for FCAS enablement/revenue.

2.2 Koonibba

There is anecdotal evidence that the community is interested in an alternative power supply arrangement. Community leaders have suggested that a communal model of procuring power may be preferable to individual retail contracts for each dwelling. This communal model would involve the Management Committee administering a common metering system and allocating costs internally in a fair and targeted manner. ITP has been informed this model would align with community practices for many other services.

Two business models are considered below. The first option assumes SAPN retains ownership of the local network and the second option assumes SAPN facilitates sale of its network to a private third party. While it is unlikely that SAPN will want to relinquish ownership of the local network, this option is included for completeness.

2.2.1 Community management corporation

In this model, a 3rd party could develop and construct in-front-of-meter generation/storage assets. The assets could be funded by a government grant to allow the benefit of revenues to flow to households in Koonibba. This model creates some complexity with ownership/operation and billing/cost recovery, with the options being:

1. (Preferred): A community entity owns the central asset (uses grant funding to purchase the development from the 3rd party developer at the point of construction). Households retain their existing retailers, and the community entity could i) take on financial responsibility for household electricity bills (without becoming their retailer), or ii) pay each household a quarterly dividend that could be used to offset their electricity bill costs, or iii) establish/manage a community fund for other electricity cost reduction measures such as subsidising more efficient appliances. Options ii) and iii) would provide a greater incentive for household energy efficiency. A hybrid approach could also be used, where each household is allocated an amount which is first used to pay the bill, with any excess payable to the household. If the community entity were to take on the responsibility of paying electricity bills, it would need to establish administrative procedures to receive household electricity bills (this can be organised through each retailer) and pay them.
2. A 3rd party using grant funding owns the assets, becomes a retailer, and sells electricity directly to the participating households at lower-than-normal retail rates and sells any excess electricity from the plant to households outside Koonibba or to the spot market. This option is not preferred because it lacks any community ownership. In addition, the 3rd party would seek profit, potentially reducing the revenues to be used to reduce household electricity bills.
3. A community entity using grant funding owns the central asset and obtains a retail licence to sell the electricity at lower-than-normal rates to participating households and sells any excess electricity from the plant to households outside Koonibba or to the spot market. This option is not recommended because the process and financial requirements of becoming a retailer are non-trivial.

Under the preferred option, the community entity would need to develop, recruit or contract expertise in management of the in-front-of-meter generation/storage assets. This could involve:

- Having non-specialist operation and maintenance activities (e.g. mowing, cleaning, etc.) conducted by community members
- Contracting specialist operation and maintenance activities (e.g. electricity and LGC trading, performance monitoring, troubleshooting, etc.)

The corporate structure of the entity may take on many forms including incorporated association, company limited by guarantee, community trust or community corporation. The Koonibba Community Aboriginal Corporation is a community entity that already exists within the Koonibba community and there may be an opportunity to repurpose or utilise such an entity for the purpose outlined above.

2.2.2 Privately-owned embedded network connected to the interconnected grid

In this model, a private entity owns the electricity network that is connected to the main grid at a single metered connection point. The embedded network operator sells electricity to consumers within the embedded network under an exemption from the AER and needs to meet prudential requirements that are equivalent to those required of an authorised energy retailer. Consumers within an embedded network have the option to buy electricity from an external retailer or the embedded network operator. This option may increase costs to consumers due to prudential requirements involved and the private entity would need to purchase the existing local network from SAPN. This option is not recommended because the process and financial requirements of becoming an embedded network operator are complex and non-trivial.

3 Network Infrastructure

SAPN provided an extensive GIS database covering all its transmission and distribution assets in the Eyre Peninsula. The GIS database included sub-transmission, substation, and distribution assets all the way down to low voltage service lines.

3.1 Kimba

The GIS data indicates that the Kimba township is supplied by an 11 kV feeder emanating from Caralue 66/11 kV zone substation, approximately 27 km southwest of the town (Figure 5). Much of the surrounding rural area is supplied by 19.1 kV single wire earth return (SWER) lines. The substation has a capacity of 3.25 MVA. Caralue zone substation has one other 11 kV feeder, which appears to be a dedicated supply for a communications facility on Caralue Bluff.

Figure 5: Local network around Kimba

3.2 Koonibba

Koonibba is connected to a ring network formed by the SWER line CD20. The town can also be supplied via CD15, which is connected to CD20 by a normally open switch. Koonibba is relatively close to the main 11 kV distribution feeder for the area (CD02). This feeder follows the Eyre Highway and supplies the town of Penong further west. The section of SWER line between the Eyre Highway and Koonibba runs through an area of isolated forest and scrub before crossing open farmland and arriving in the town from the east. There is approximately 7.3 km of SWER line between the 11 kV feeder CD02 and the town. This relatively short distance is not likely to contribute significantly to the reliability of power supply to Koonibba, particularly given there is an alternative supply path via CD15 to the east. This network configuration around Koonibba suggests that reliability issues are more likely to occur upstream and have broader impacts on the region.

The GIS database indicates that Koonibba is serviced by single-wire earth return (SWER) system. The town can be supplied either via CD20 which taps off the 11 kV sub-transmission line CD02 to the south, or CD15 which runs from Ceduna through the surrounding country. The local network is shown in Figure 6 and Figure 7.

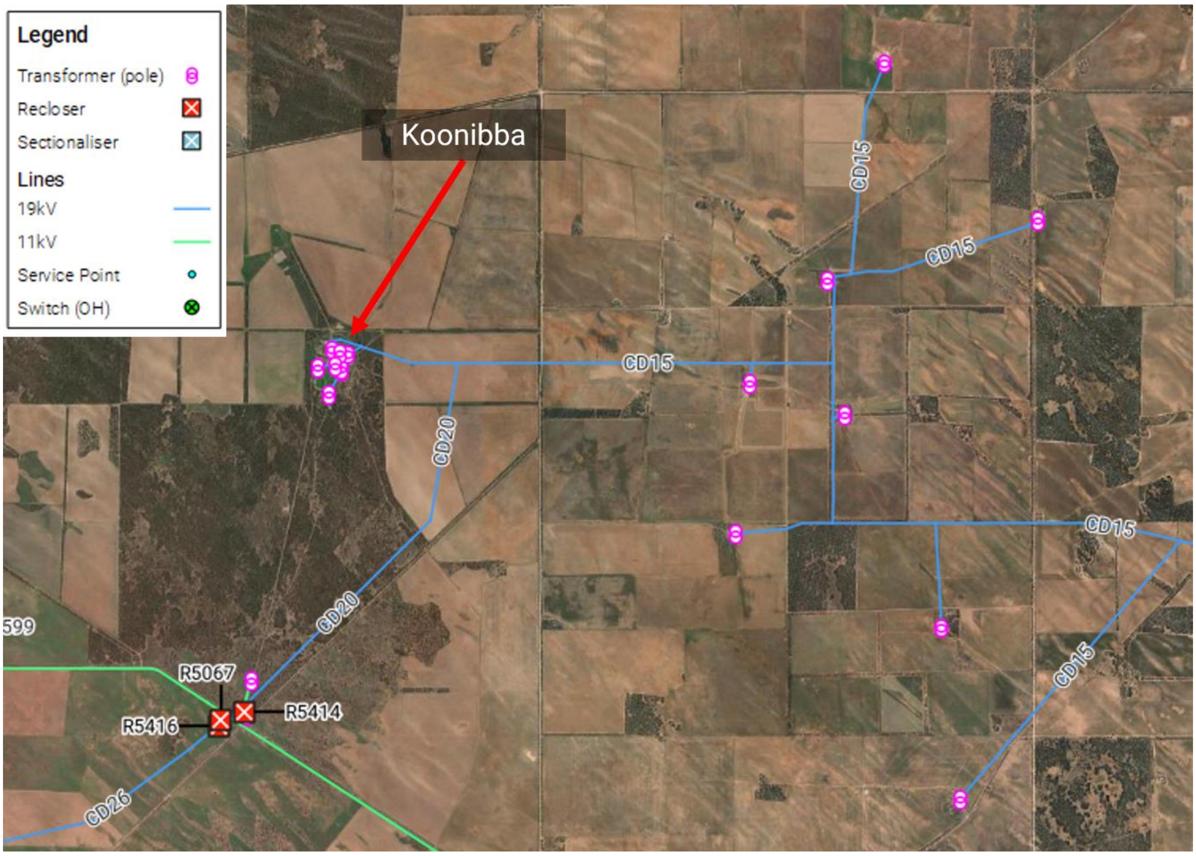


Figure 6: Feeder CD20 supplying Koonibba

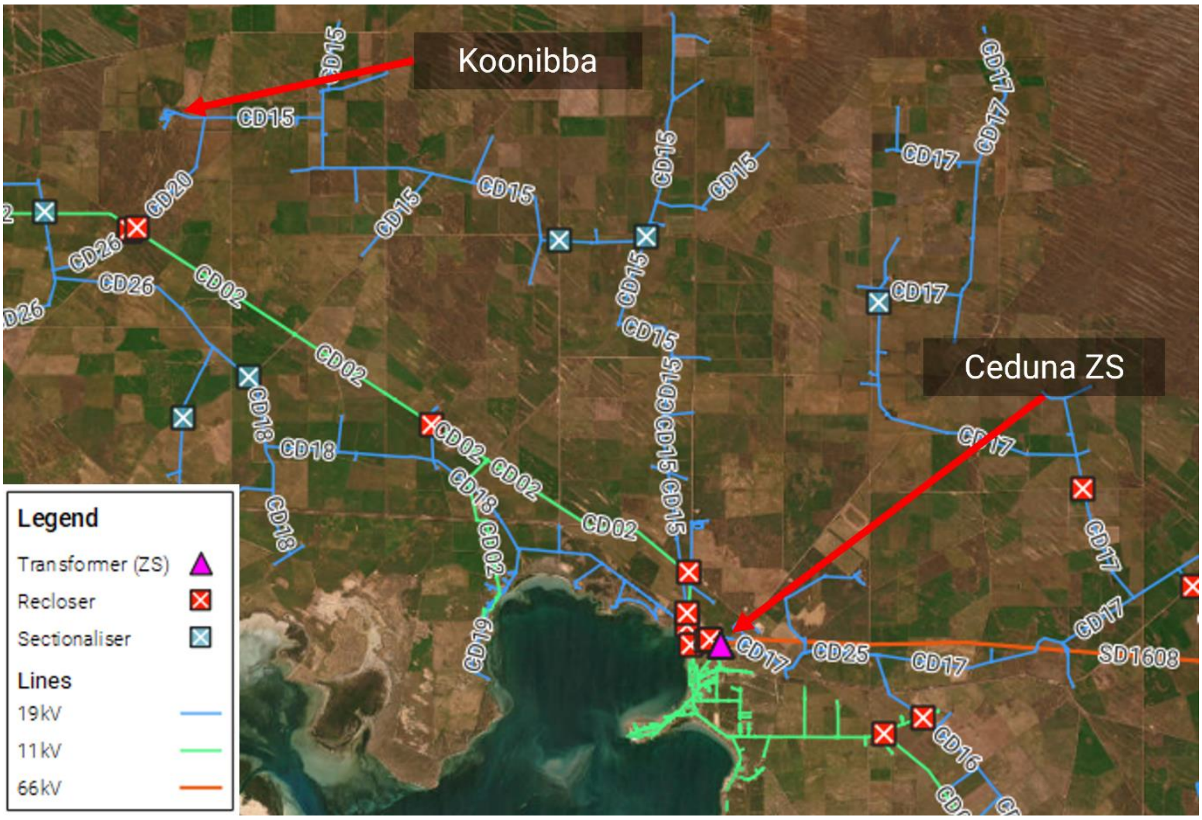


Figure 7: Local network supplying Koonibba

3.3 Sceale Bay

The GIS database indicates that Sceale Bay is supplied by a single-wire earth return (SWER) line identified as SB17 (Figure 8). SB17 is supplied by an 11 kV feeder (SB02) emanating from Streaky Bay 66/11 kV zone substation. SB17 supplies Sceale Bay and several other small towns and rural localities. The spur that leads directly to Sceale Bay is shown in Figure 9, which shows six intermediate transformers between the network junction and the town.

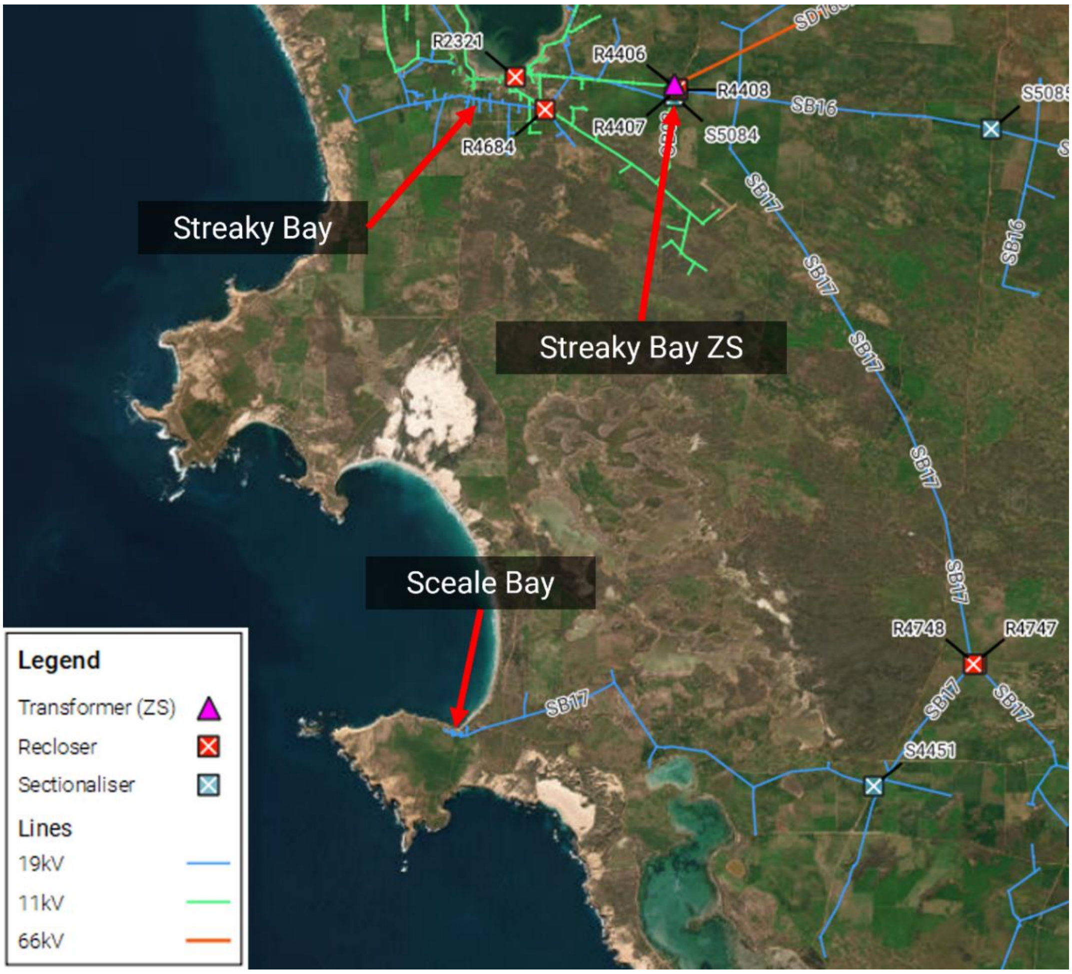


Figure 8: Streaky Bay local network

Figure 9: SB17 spur to Sceale Bay

4 Existing Generation

4.1 Kimba

There are no registered embedded generators connected to the network in the vicinity of Kimba and ITP is not aware of any large, unregistered generators (e.g., 1.5-5 MW solar farms) connected to Caralue zone substation distribution lines. ITP is also not aware of any large renewable energy generators proposed, or under construction in the region.

Many rooftop PV systems are visible on satellite and aerial imagery of the town. There is also a small PV and BESS system at SA Water's Kimba Pump Station. CER postcode data (5641) suggests there are 250 small scale (i.e., <100 kWp) PV systems installed in the region, with combined AC capacity of approximately 1,650 kW. Most of the postcode area overlaps the District Council of Kimba area and is therefore a reasonable approximation of embedded PV capacity in the microgrid area. This aligns with information from SAPN's DAPR which suggests there is PV capacity of 1,600 kVA connected to the local distribution network.

The existing generation already supplies a substantial portion of local demand, and SAPN's Load Forecast Dashboard suggests negative demand reaches approximately -600 kVA at present. Integrating this into a microgrid may require retrofitting existing systems to enable some level of orchestration as most existing PV will not be set up to be controlled by external devices.

4.2 Koonibba

There are no registered embedded generators connected to the network in the vicinity of Koonibba, and ITP is not aware of any large, existing unregistered generators (e.g., 1.5-5 MW solar farms) connected to Ceduna Zone Substation distribution lines. There is a 4.95 MW solar farm outside Ceduna that has been approved.

There is no visible rooftop PV in any of the satellite and aerial imagery ITP examined. While CER postcode data suggests there is approximately 4.3 MWp of installed PV in the region, this includes the substantial townships of Ceduna and Penong. These observations support the conclusions drawn from the seasonal demand profiles, which indicate very limited PV in Koonibba, but a significant amount in the Ceduna ZS supply area.

4.3 Sceale Bay

Streaky Bay Solar Farm is a 3 MW solar PV generator located about 1 km west of Streaky Bay Zone Substation. While this facility is not on the same feeder as Sceale Bay, it is a key contributor to existing reverse power flows at the substation. According to SAPN's 2021 DAPR, the solar farm may have a runback scheme in place to curtail generation when the substation transformers are approaching their operational limits. The presence of this solar farm may constrain any generation at Sceale Bay should the town remain connected to the grid.

Existing residential and commercial PV arrays in the Streaky Bay area (postcode 5680) have a combined capacity of 4.11 MW according to the CER register of small-scale PV systems. The CER postcode data does not have sufficient resolution to determine the current capacity of PV connected to SB17, or within Scelae Bay township itself. Many rooftop PV systems are visible in satellite imagery of Sceale Bay however, and ITP assumes that penetration of PV is comparable to the surrounding areas. The substation has recorded reverse power flow up to 3 MVA due to the combination of distributed PV and Streaky Bay solar farm, which is below the firm reverse power rating of 3.75 MVA.

5 Meteorology

5.1 Irradiance

The solar resource in the Eyre Peninsula is good, but seasonal variance is considerable owing to the high latitude. Average monthly horizontal irradiance around Kimba, Koonibba, and Sceale Bay is plotted in Figure 10, Figure 11, and Figure 12 respectively. The solar resource across Australia is shown in Figure 13.

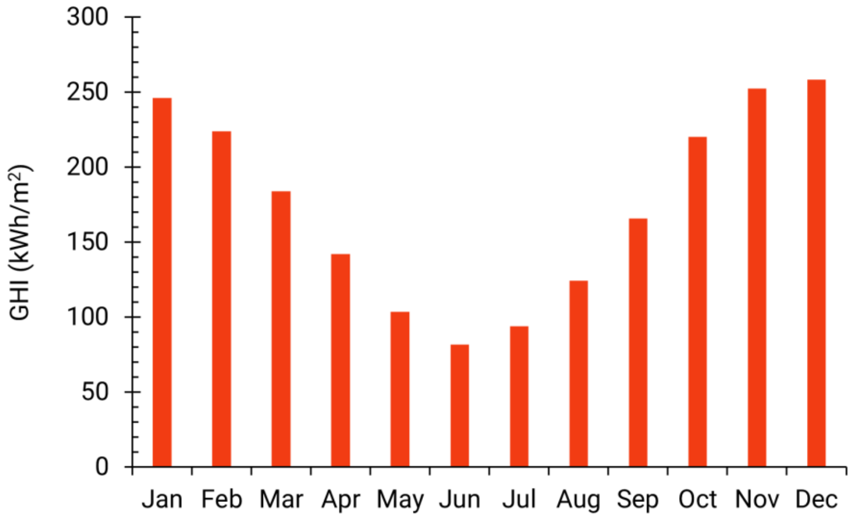


Figure 10: Monthly solar resource at Kimba (source: Bureau of Meteorology)

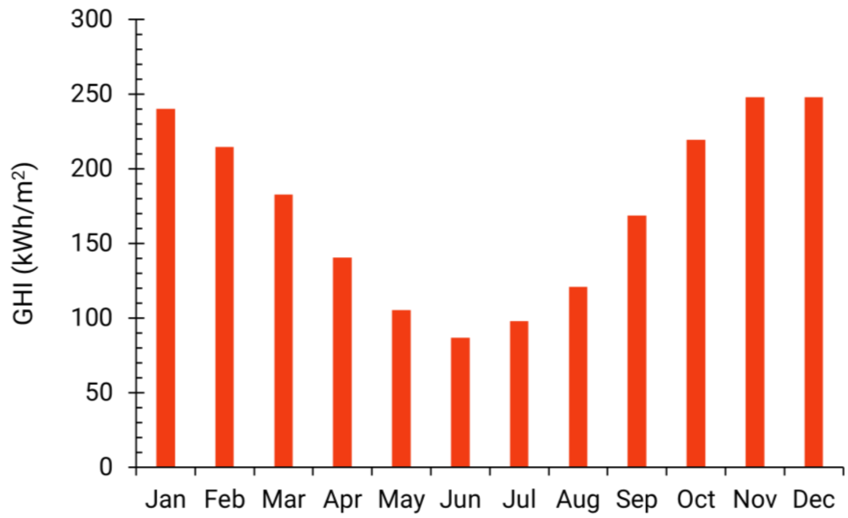


Figure 11: Monthly solar resource at Koonibba (source: Bureau of Meteorology)

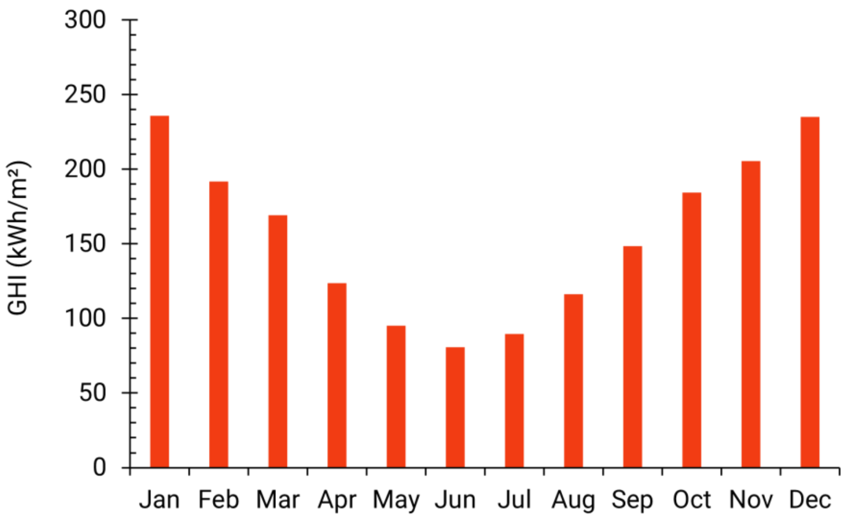


Figure 12: Monthly solar resource at Sceale Bay 1992 – 2022 (source: Bureau of Meteorology)

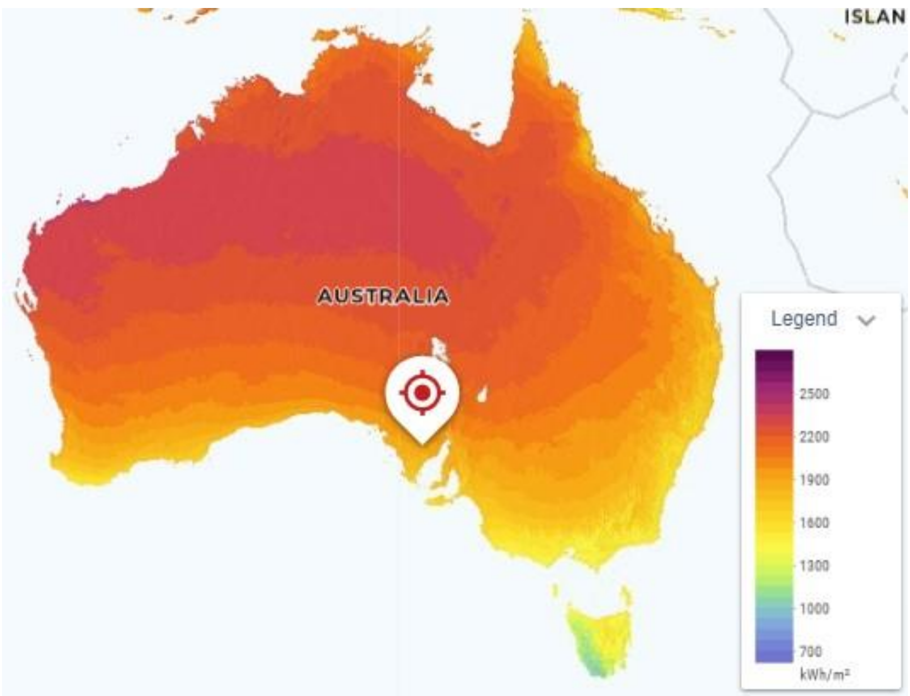


Figure 13: Solar resource across Australia (source: Global Solar Atlas)

5.2 Temperature and rainfall

Other climate statistics for the past 30 years are summarised in Figure 14, Figure 15, and Figure 16 for Kimba, Koonibba, and Sceale Bay respectively. Rainfall is typically highest in winter, coinciding with lower temperatures.

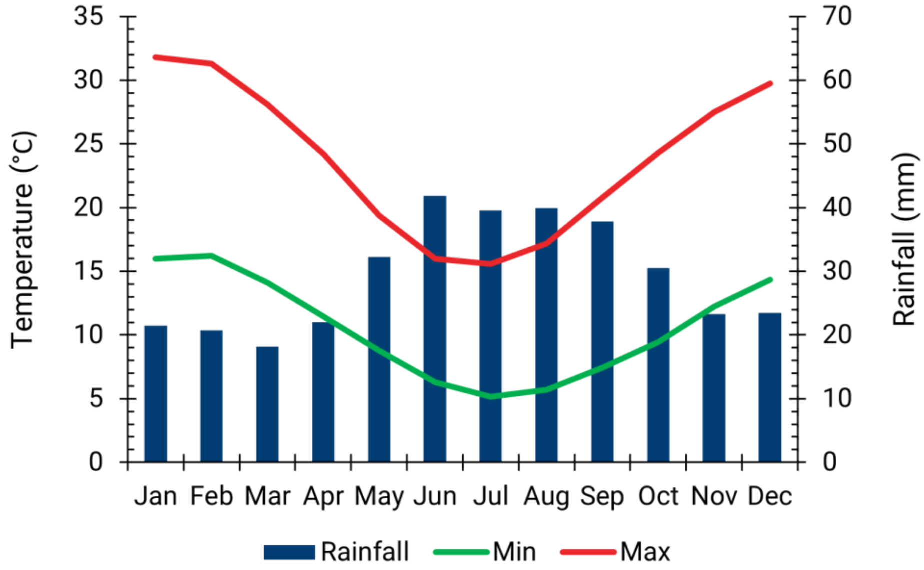


Figure 14: Average temperature and rainfall at Kimba 1992 – 2021 (source: BOM)

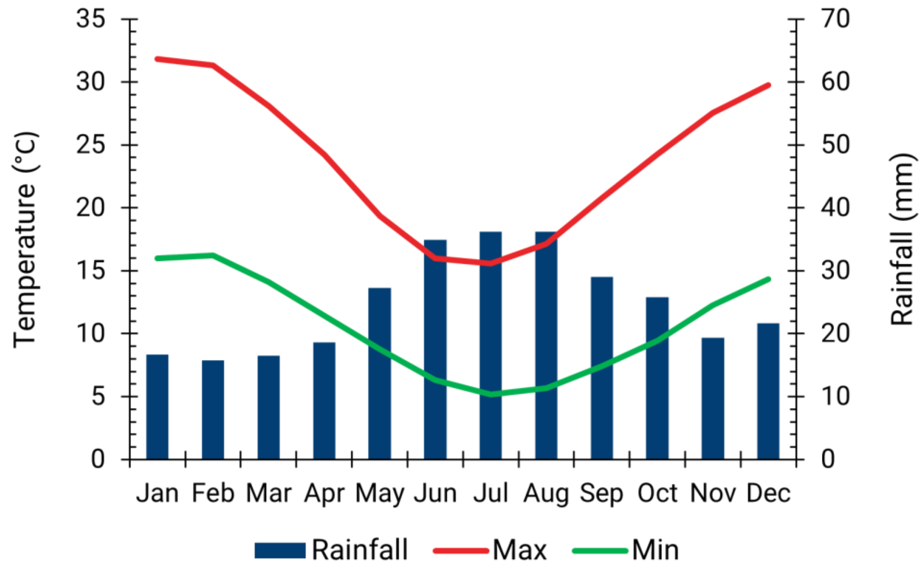


Figure 15: Average temperature and rainfall at Koonibba 1992 – 2021 (source: BOM)

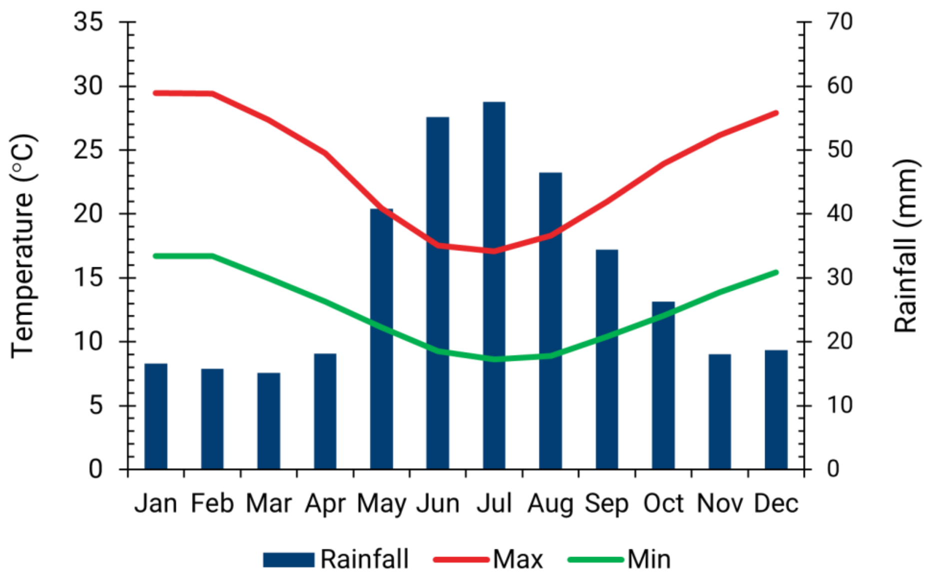


Figure 16: Average temperature and rainfall at Streaky Bay 1992 - 2022 (source: BOM)

6 Demand

6.1 Historical

6.1.1 Kimba

SAPN provided interval metering data for Caralue Zone Substation. This data covered the period from 2011 to 2022 in half-hourly time steps and is plotted in Figure 17 below. The 11 kV feeder CV08, which supplies Kimba and the surrounding area, accounts for most of this demand. SAPN does not currently have power metering on CV08, and hence ITP used a combination of the Caralue ZS data, average demand at distribution transformers, and metering data for CV08 to estimate the demand profile.

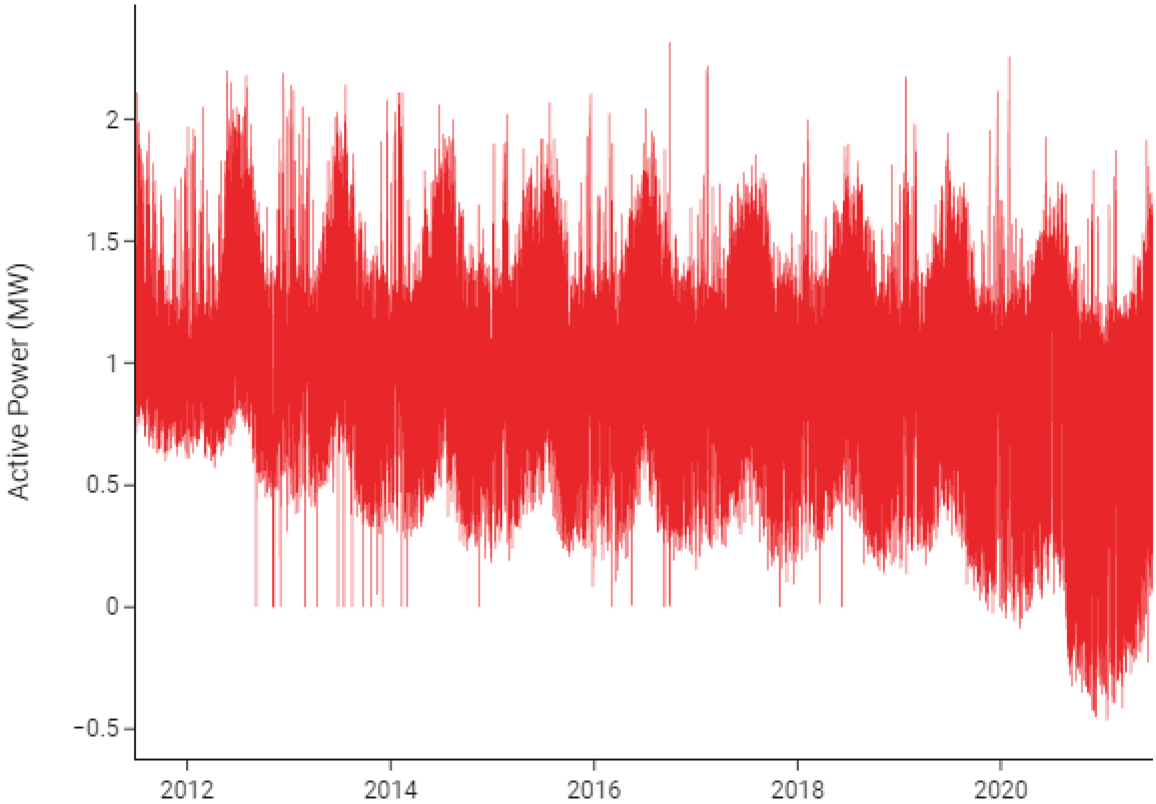


Figure 17: Historical demand at Caralue zone substation

The average demand for the region has been declining by about 30 kW per year for the past decade. Peak demand in 2021 was 1,920 kW, while average demand was 686 kW. The mean daily demand profiles from 2020 are shown in Figure 18. Minimum demand occurs during the middle of the day consistently across all seasons, indicating the high penetration of solar PV in the region. There are strong early morning and evening peaks, particularly in winter.

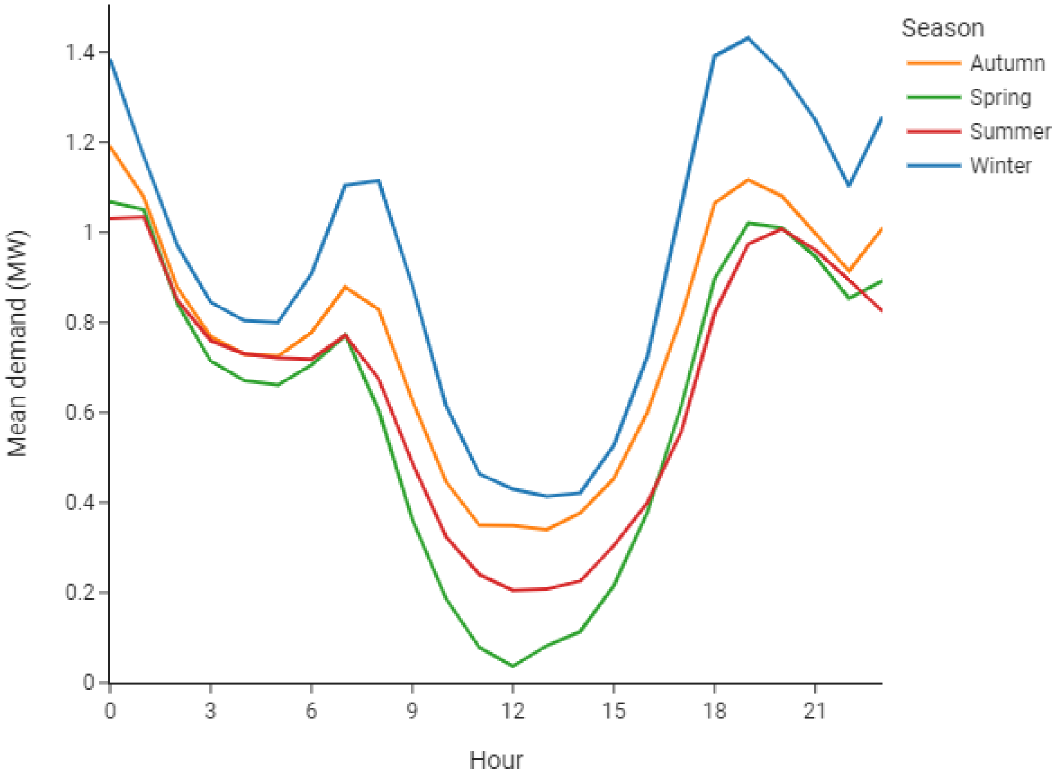


Figure 18: Seasonal mean demand profiles in 2020

6.1.2 Koonibba

SAPN provided interval metering data for feeder CD20 emanating from Ceduna Zone Substation. This data covered the period from May 2021 to May 2022 in hourly time steps and is plotted in Figure 19 below. There are many instances of zero demand, particularly from late 2021 onwards. This could indicate frequent power outages, or loss of communications. Peak demand over this period was 176 kW and average demand was 57 kW.

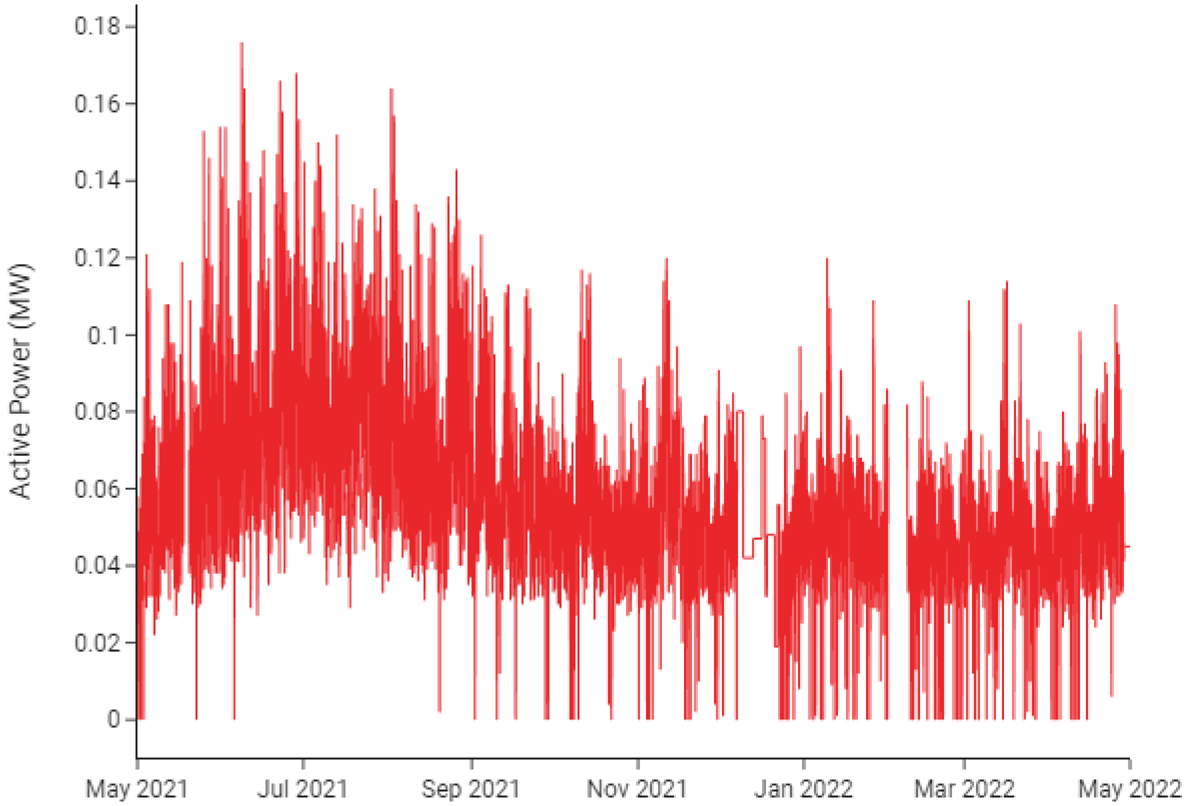


Figure 19: Hourly demand in Koonibba

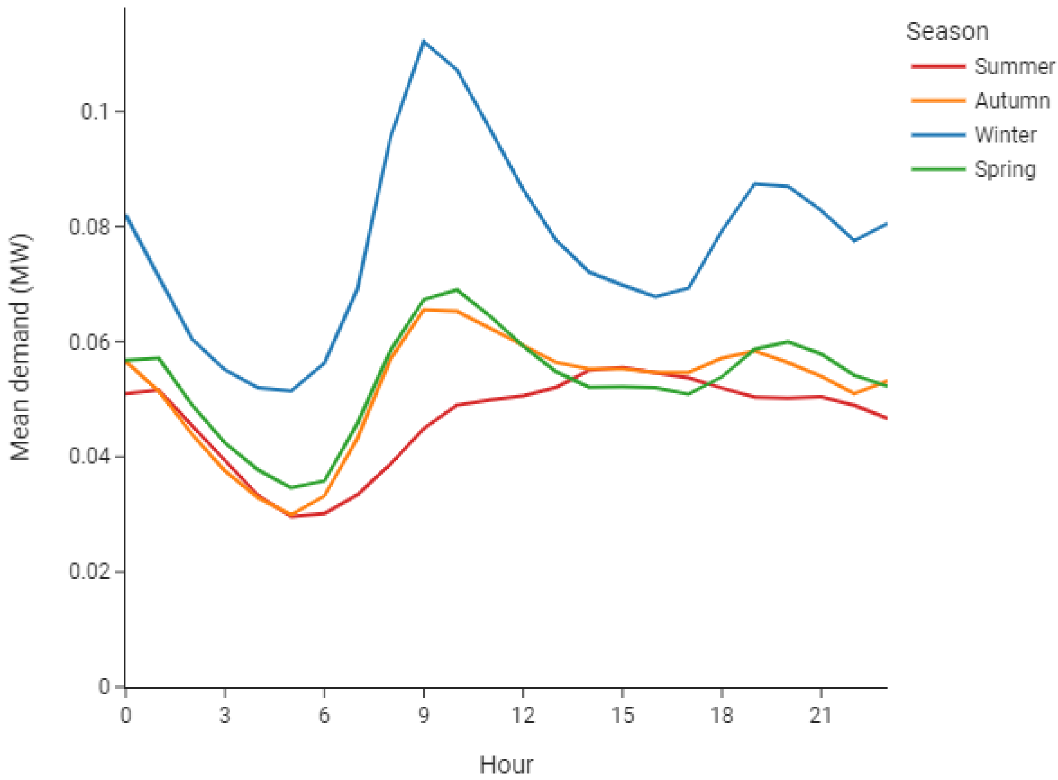


Figure 20: Seasonal daily demand profiles on feeder CD20

The seasonal demand profiles for Koonibba in 2020 – 2021 shown in Figure 20 show a strong early morning peak, particularly in winter, with a secondary peak in the evening. There is no evidence of solar generation reducing demand in the middle of the day, which supports observations of the site visit and aerial imagery. This contrasts with the demand profiles for the broader Ceduna area, which feature significant solar generation during the middle of the day as shown in Figure 21.

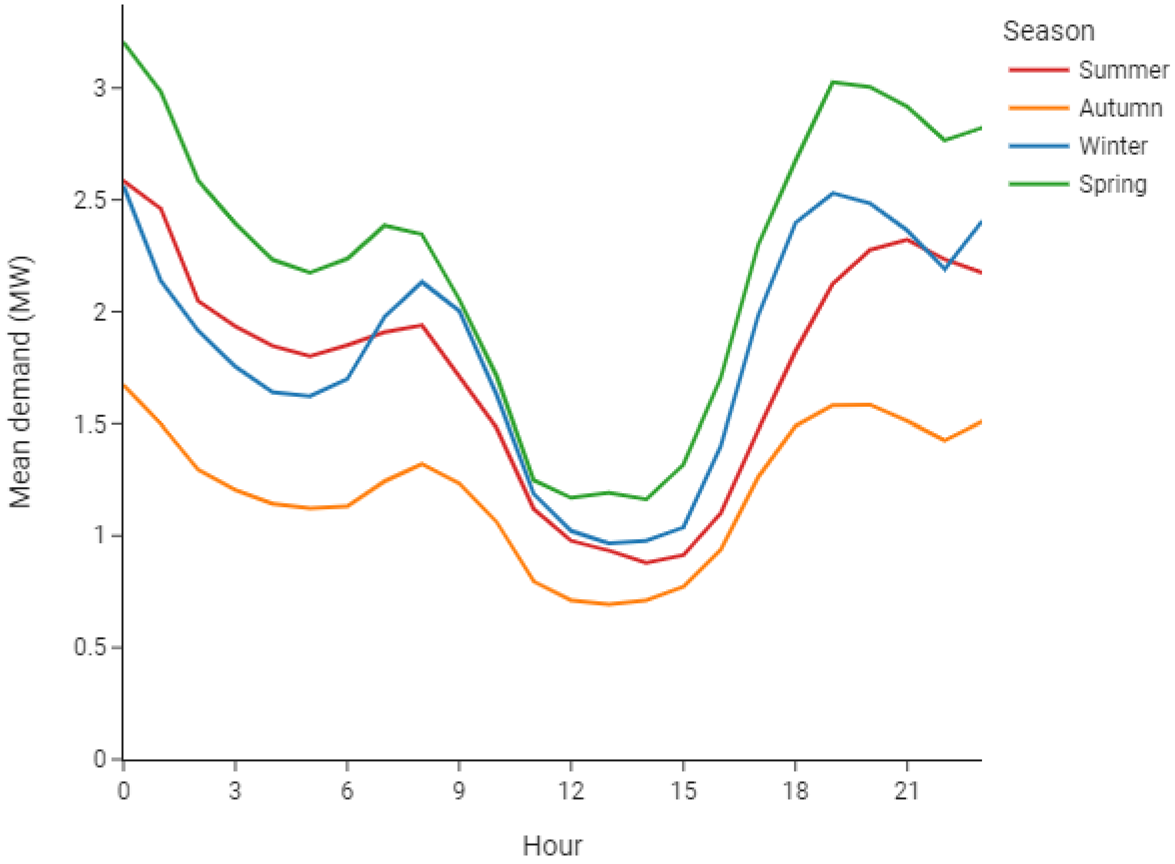


Figure 21: Seasonal daily demand profiles at the Ceduna Zone Substation

6.1.3 Sceale Bay

SAPN provided interval metering data for the 11 kV distribution feeder SB02 emanating from Streaky Bay Zone Substation. SB02 supplies the SWER line SB17, along with several other SWER lines, and downstream customers. SB17 supplies Sceale Bay, several other small towns, and many single customers. SAPN currently does not meter SB17 directly, and hence ITP used data for SB02 to estimate the load profile at Sceale Bay.

The data covered the period from May 2021 to May 2022 in half-hourly time steps and is plotted in Figure 22 below. There are several gaps in the data, and a period in late May 2021 with data that appears to be erroneous. ITP used the rest of the dataset to fill in these gaps to develop a complete, baseline demand trace.

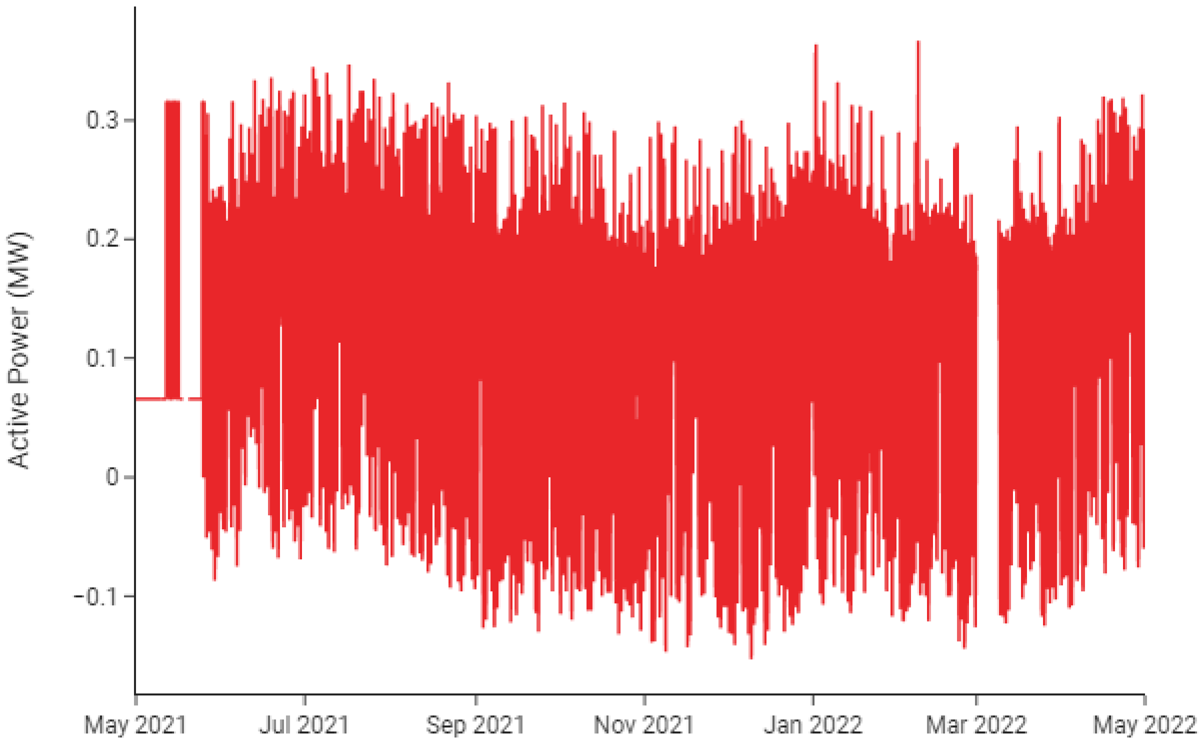


Figure 22: Time series of 30 min metered power on SB02

ITP also accessed publicly available metered data for Streaky Bay substation. This data covers the period from 2011 to 2021 and is partially shown in Figure 23. Average demand has been declining for the past decade. The commissioning of Streaky Bay solar farm can be seen in this dataset as a step change in reverse power flow around May 2021.

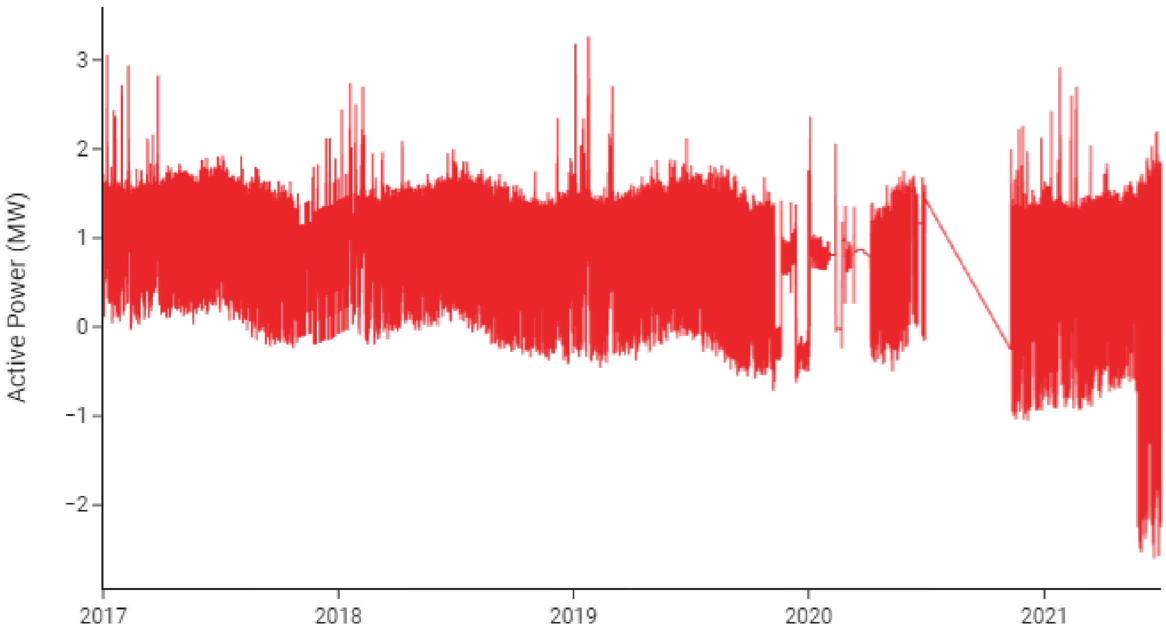


Figure 23: Time series of 30 min metered active power at Streaky Bay Zone Substation

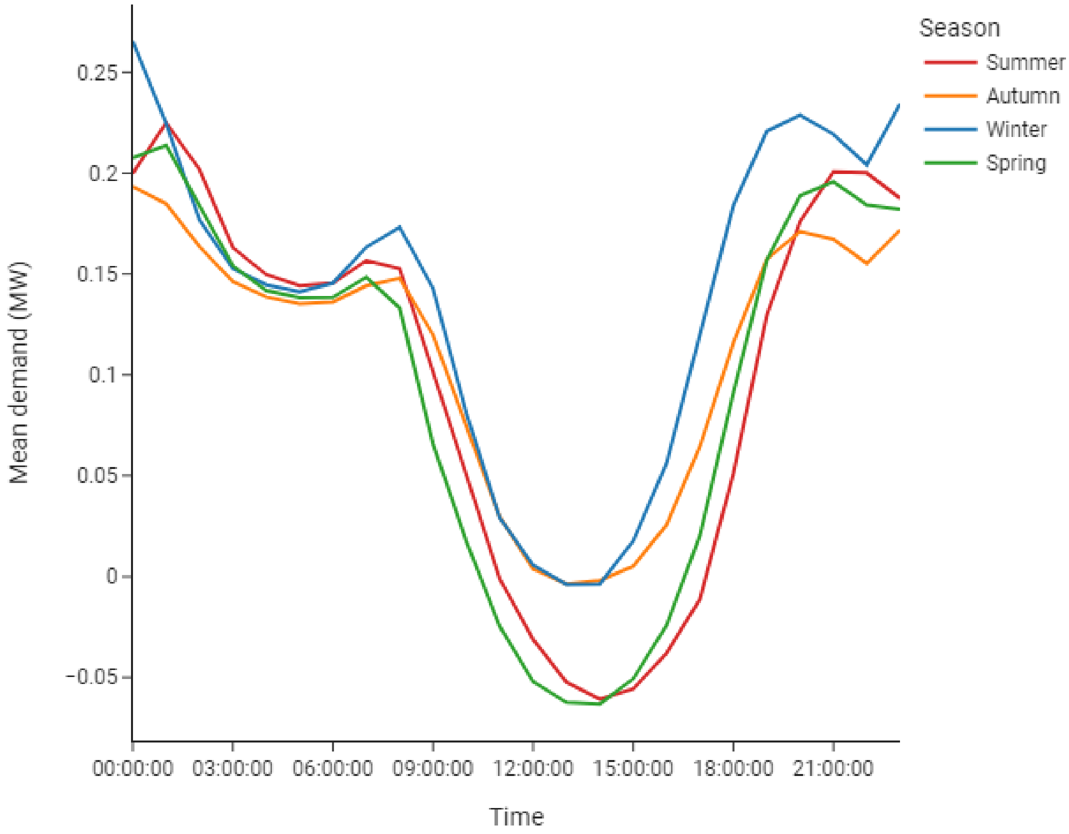


Figure 24: Seasonal mean demand profiles on SB02

The mean daily demand profiles from 2021 are shown in Figure 24. Minimum demand occurs during the middle of the day consistently across all seasons, indicating the high penetration of solar PV in the region. There are moderate early morning and evening peaks, which are more pronounced in winter. The negative demand in spring and summer indicates that reverse power flows are common on the feeder.

6.2 Forecast methodology

Forecasting load growth is a central task for planning and optimising power generation capacity. Demand for electricity is expected to increase significantly as fossil fuels are gradually replaced with electric alternative in many applications. This includes uptake of electric vehicles, and replacing domestic gas use for cooking, water heating, and space heating. The ongoing adoption of distributed energy resources (DER), including rooftop solar PV and battery energy storage systems (BESS), is expected to reshape demand profiles. South Australia already experiences frequent negative pricing events, and reverse power flows are common across many zone substations due to the high penetration of solar PV. To capture all these anticipated changes in demand, ITP drew on authoritative forecasts developed for AEMO's Integrated System Plan (ISP) and localised them to account for the peculiarities of each site.

6.3 Forecast

ITP constructed a 30-year forecast for each site by scaling the baseline load profile each year to account for population change, and then adding modified ISP traces for the matching year. The resulting maximum, minimum, and average demand forecasts are shown in Figure 25, Figure 26, and Figure 27 for Kimba, Koonibba, and Sceale Bay respectively.

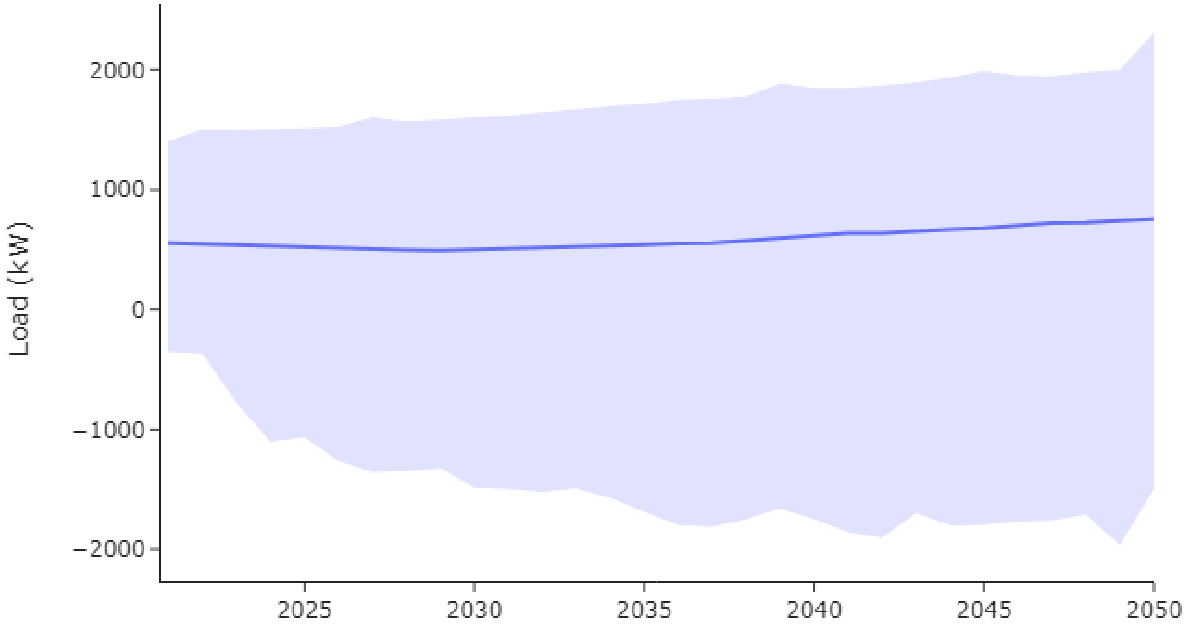


Figure 25: Mean, maximum, and minimum demand forecast for Kimba

Demand has been decreasing in Kimba in recent years, likely driven by the combined impacts of slow population decline, uptake of solar PV, and uptake of energy efficient devices. The mean demand forecast reflects this, with a steady decline until around 2028. After this the combined impact of electrification and electric vehicle charging reverses the trend, leading to steady demand growth to the end of the forecast period.

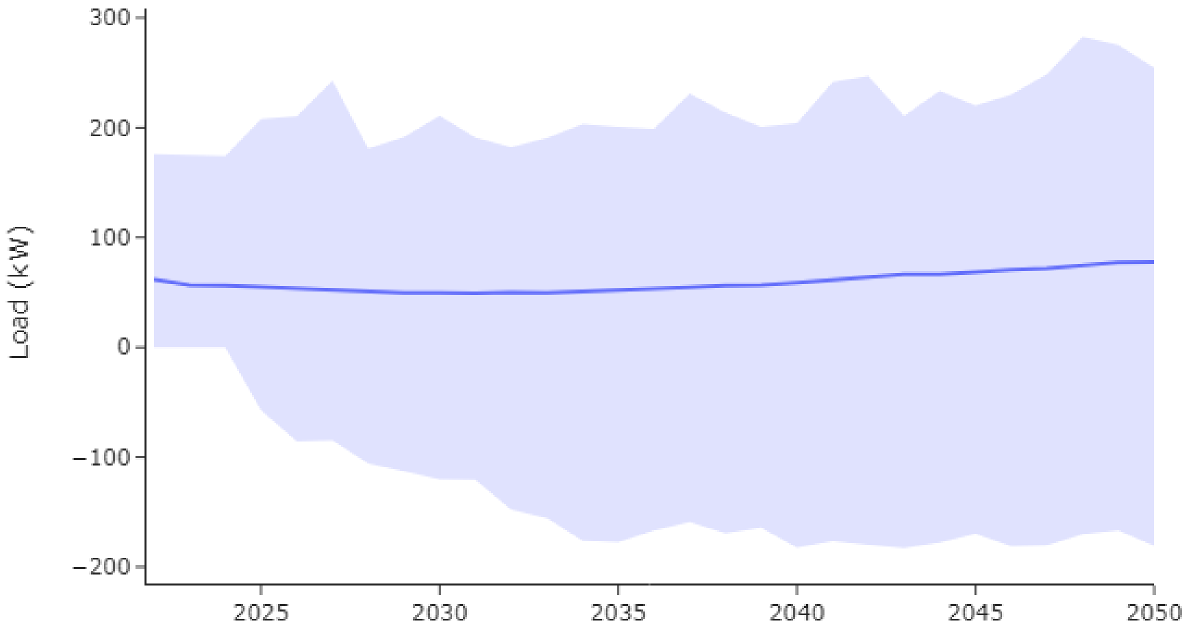


Figure 26: Mean, maximum, and minimum demand forecast for Koonibba

Recent history suggests that demand in Koonibba is likely to remain stable or decline slightly with long term population decline and future uptake of solar PV. Late in the forecast period, the combined impact of electrification and electric vehicle charging reverses the trend, leading to steady growth.

Demand has been relatively stable in the Streaky Bay region in recent years. There is anecdotal evidence of population growth in Sceale Bay, and a significant number of new dwellings are under construction. ITP has assumed moderate population growth, which combined with electrification and uptake of EVs leads to steady demand growth over the full forecast period.

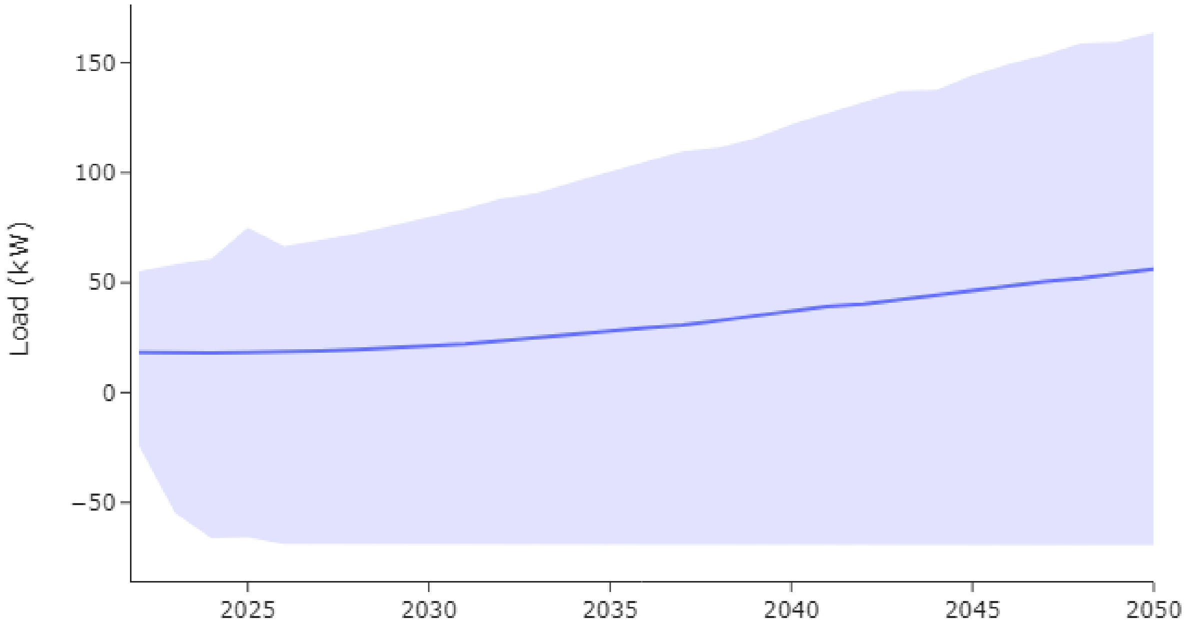


Figure 27: Mean, maximum, and minimum demand forecast for Sceale Bay

Load profile forecasts for selected years are shown in Figure 28, Figure 29, and Figure 30 for Kimba, Koonibba, and Sceale Bay respectively. ITP has not attempted to remove existing PV generation from the demand profile, and hence the solar PV shown in the profiles represents only additional behind-the-meter PV generation.

The change in the average daily profile demonstrates several important trends. Steady uptake of solar PV continues to hollow out midday demand, driving increasing instances of reverse power flow. This is partially offset by increasing electrification, distributed energy storage, and coordinated EV charging. Peak demand moves more strongly into the early evening, partly driven by uncoordinated EV charging, which adds significantly to demand as many workers return home from work.

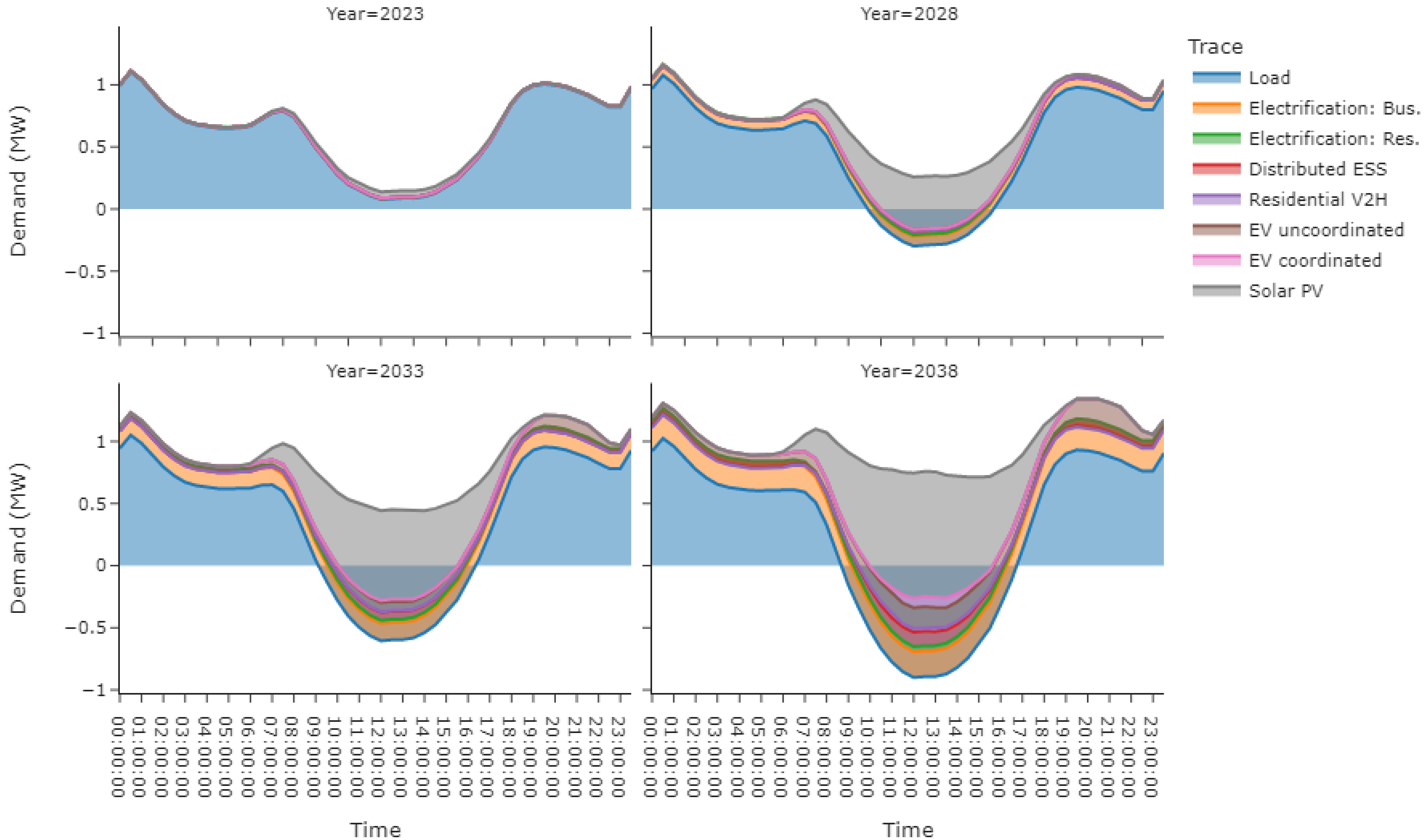


Figure 28: Kimba forecast average demand profile for selected years

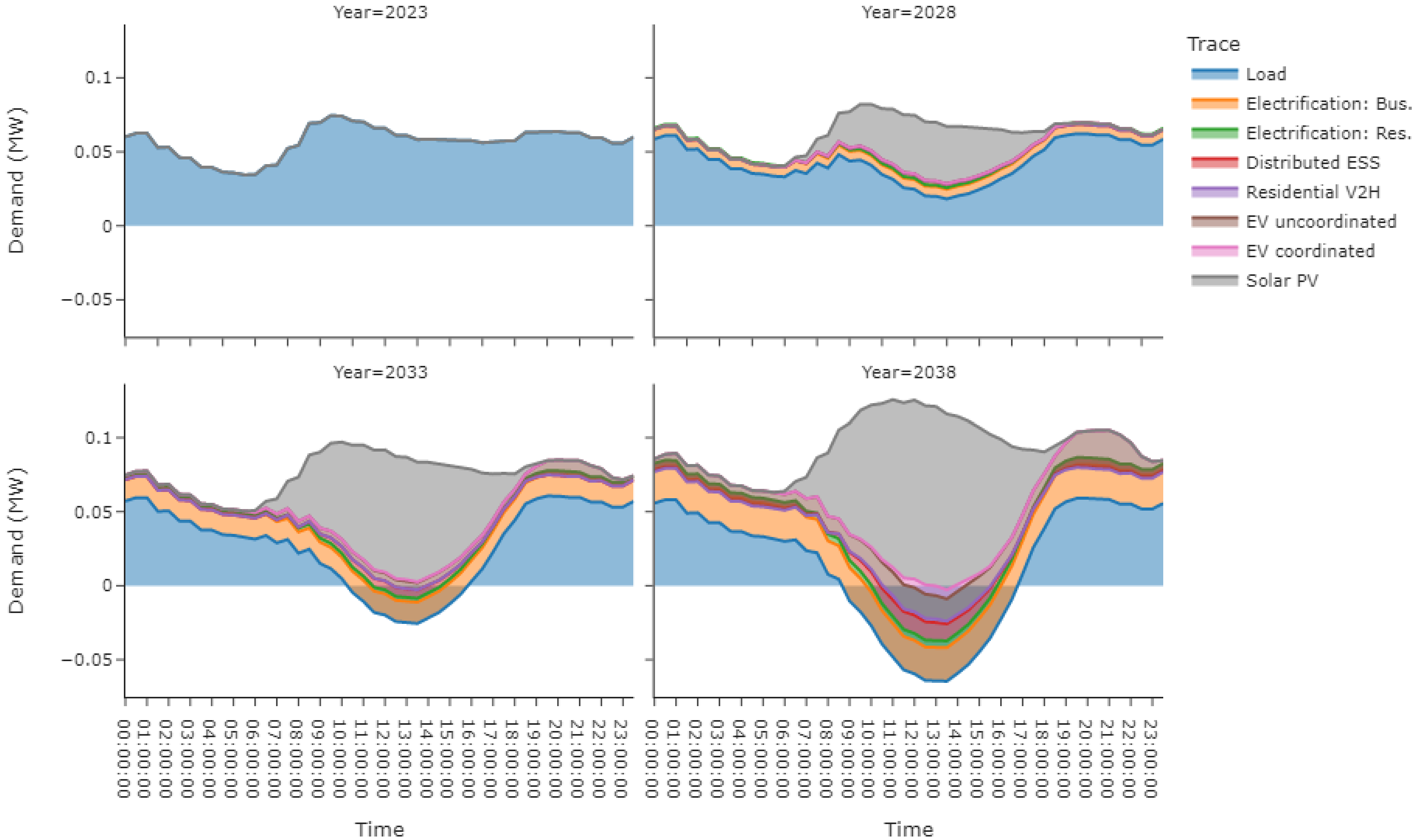


Figure 29: Koonibba forecast average demand profiles for selected years

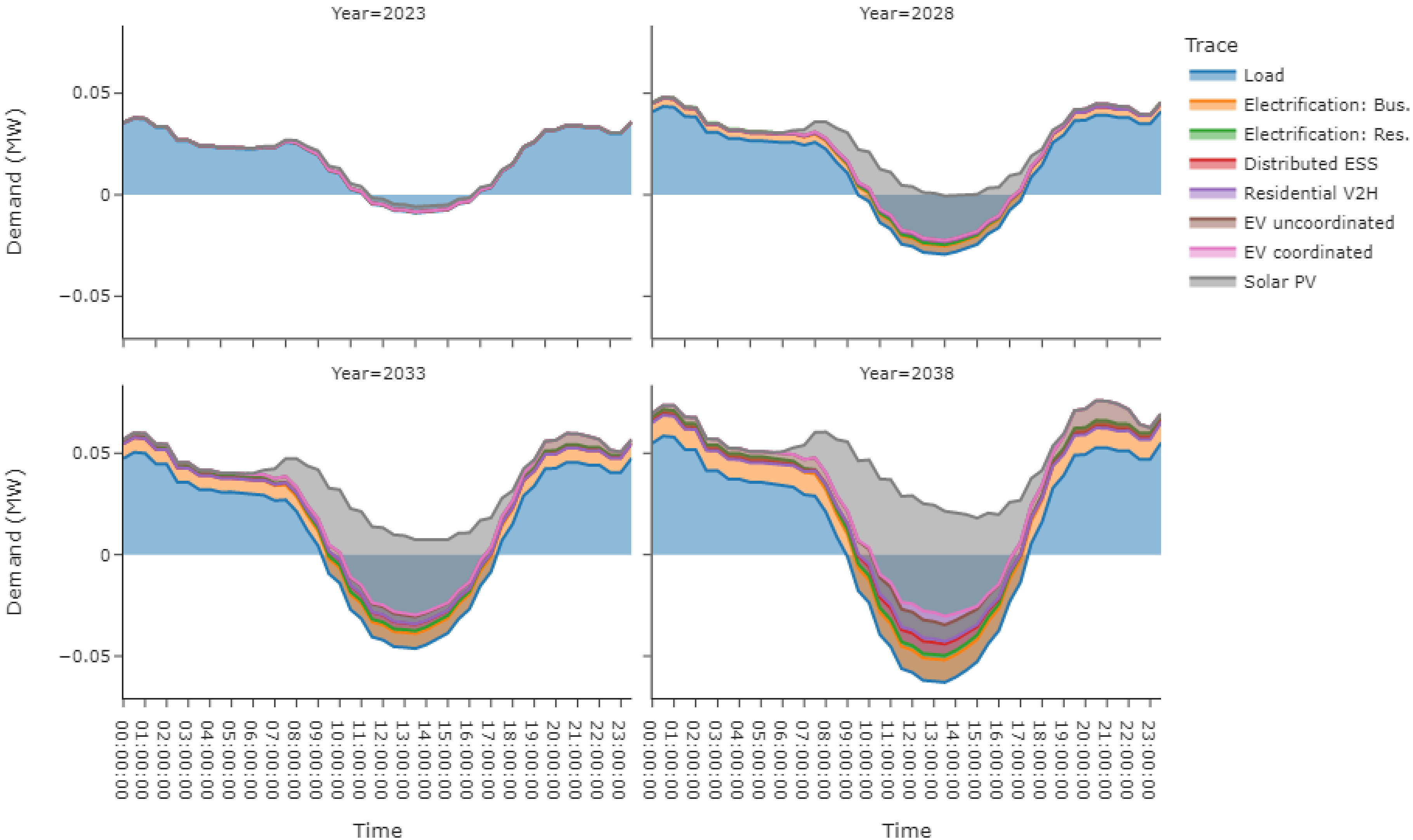


Figure 30: Sceale Bay forecast average demand profile for selected years

7 Concept Design

7.1 Overview

This study considers an intermittent microgrid powered by a centralised PV and BESS for each site. The capacities of major generating plant items are summarised in Table 1. These configurations exclude a diesel generator and would instead require the community to engage in a small amount of "demand response" during islanding events to conserve energy. On average, the PV and BESS capacity proposed is sufficient to ensure >90% of local demand is served by local generation/storage in island mode in year 1 (2025).

Table 1: Centralised generation capacities for each proposed intermittent microgrid

Site	PV modules (MWp)	PV inverter (MW)	BESS Inverter (MW)	Battery (MWh)
Kimba	4.6	3.5	4.5	18
Koonibba	0.58	0.36	0.43	1.7
Sceale Bay	0.26	0.16	0.30	0.63

While outside the scope of these studies, ITP also considered:

- Centralised PV & BESS with diesel back up
- BESS only systems, owned by SAPN, designed to reduce outage time caused by upstream faults
- A combination of isolated microgrids for the townships, and IPS for outlying customers

These options are not explored in detail in this report as our analysis found that they are not compelling options in these locations. Nevertheless, isolated microgrids and IPS may have potential in other parts of the Eyre Peninsula, and BESS-only systems may have potential in parts of the network that experience more frequent, short duration outages.

The extent of the proposed intermittent microgrids are illustrated in Figure 31, Figure 32, and Figure 33 for Kimba, Koonibba, and Sceale Bay respectively.

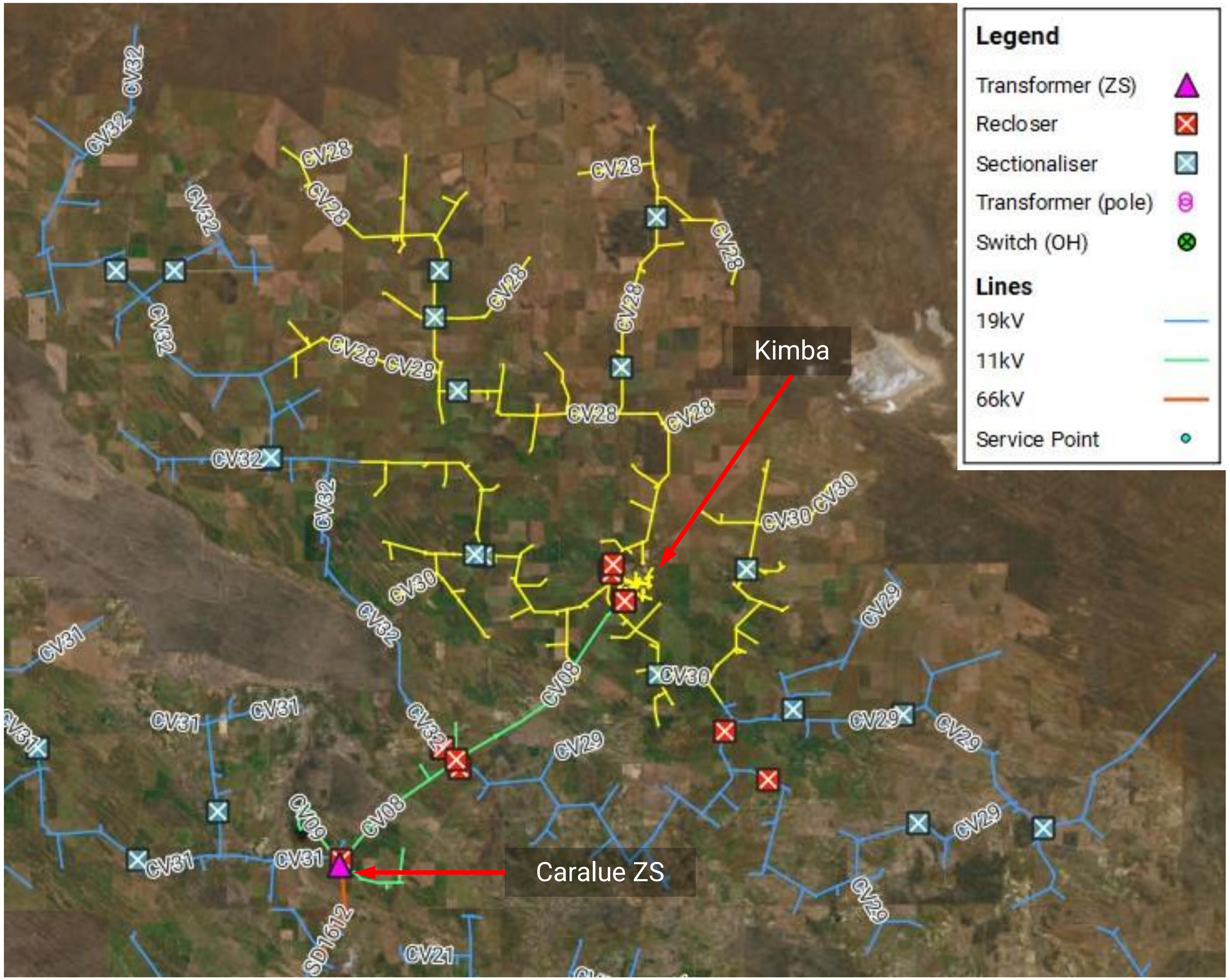


Figure 31: Proposed extent of the intermittent microgrid for Kimba (yellow)

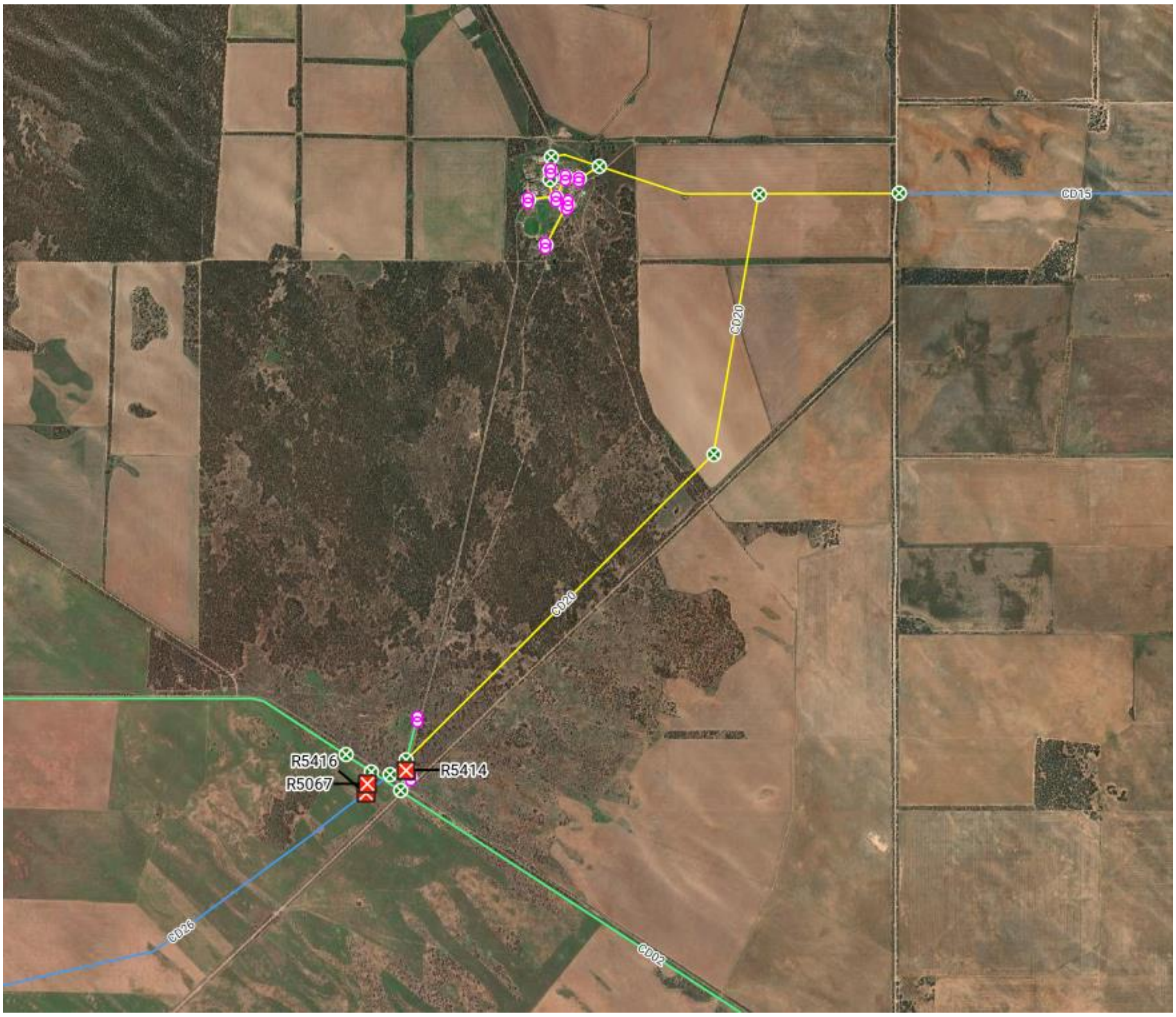


Figure 32: Proposed extent of the microgrid for Koonibba (yellow)

Figure 33: Proposed extent of the intermittent microgrid for Sceale Bay (yellow)

7.2 Embedded generation management

Various options are available for mitigating excess generation from uncontrolled, distributed PV in grid-connected and island mode, including:

- Raising the voltage at the local zone substation or distribution transformer to trigger solar inverters overvoltage protection9
- Retrofitting existing PV with communications gateways that enable remote curtailment commands to be executed10
- Installing a dispatchable load bank (recommended)

7.3 Demand management

In the absence of back-up diesel generation, there will occasionally be times when the system has an energy shortfall when operating in island mode for extended periods. To avoid outages[11] when islanded, residents and businesses would occasionally need to reduce their consumption. “Demand response” can be achieved either by:

- An ad hoc voluntary response from the community
- Granting SAPN control over demand response enabled devices (DREDs)12
- Granting SAPN control over devices via retrofit device gateways13

The voluntary model would require ad hoc requests for demand response to be sent to participating residents via SMS (or similar). These requests would communicate why demand response is required (e.g., grid outage), the severity of the incident, and expected resolution time, if known.

7.4 Islanding point

At a minimum, the following capability is required from the islanding device:

- Load make/break: to enable switching under load
- Undervoltage protection: to ensure the microgrid is isolated when the grid supply is interrupted
- Grid-side voltage sensing: to detect when the grid supply has been restored
- Remote open/close: to enable SAPN to isolate/reconnect the microgrid on command

9 Such a scheme is currently used by SAPN to increase operational demand
10 This would require agreement from PV owners and would incur costs of $500-1,500 per household for communications gateway installation
11 Until solar generation and storage is sufficient to black start the islanded grid
12 This would require agreement from DRED owners
13 This would require agreement from device owners and would incur costs of around $500-1,500 per device for communications gateway installation

7.5 Centralised generation

The centralised generation sources considered here are solar PV and battery energy storage (BESS). There are two options for coupling of PV and BESS capacity in a hybrid generation system. A DC-coupled system (i.e., PV and BESS connecting to the same DC bus) would reduce the complexities of operating a hybrid generation system, and the complexity of power systems studies required. However, there are currently few products with this capability available in the market at utility scale and hence we have assumed that the system will be AC-coupled (i.e., PV and BESS connecting to the same AC bus).

7.5.1 Solar PV

A solar PV system comprises PV modules, a mounting system, and inverters to convert the DC output of the modules into AC for export to the grid.

The proposed PV array at Kimba will be ground mounted on a single-axis tracker with steel pile foundations. The trackers will run in north-south rows and will rotate from east to west each day following the sun.

The proposed PV arrays at Koonibba and Sceale Bay will be ground mounted on a fixed-tilt, east-west mounting system with steel pile foundations. The tables will run in north-south rows with panels tilted east/west at a minimum of 8° above horizontal to allow for self-cleaning. The primary advantages of this concertina-like arrangement are that greater PV capacity can be fit on the same area of land, and no heavy machinery is required for installation, reducing installation costs significantly at small scale. The design is also low lying and compact, reducing visual impact.

Foundation designs will be determined by a structural engineer during detailed design, and after specific mounting products have been selected. These designs must account for wind loadings, ground conditions, bearing capacity, and earthquake risk.

PV module lifetime is 25-30 years, with inverter replacement typically required after 10-15 years. Mounting system lifetime depends on corrosivity and corrosion protection but is typically 25-50 years.

7.5.2 Battery energy storage

The proposed BESS will use lithium-ion (Li-ion) batteries (most likely lithium iron phosphate) and bi-directional, grid-forming inverters. Li-ion technology is currently the highest performing and lowest cost battery solution for applications that involve daily cycling.

The proposed BESS is intended to operate for 15 years before replacement. Batteries are generally warrantied for 10 years, with some vendors able to offer 15- or 20-year warranties. ITP prefers a centralised, factory-integrated solution as this minimises on-site works and commissioning risk.

When the microgrid is operating in island mode the BESS will act as the primary voltage source for the islanded grid. Therefore, the BESS inverters must have grid-forming capability with sufficient capacity to meet peak demand, maintain voltage stability, and deliver sufficient transient current to start motors, magnetise transformers, and clear faults.

7.5.3 Electrical balance-of-plant

The hybrid generating system at Kimba will include an 11 kV switchboard with motorised circuit breakers for protection and isolation of the PV and BESS, and diesel generators. The switchboard will connect to the grid via an automatic recloser.

The hybrid generating systems at Koonibba and Sceale Bay will include a new low voltage switchboard with motorised moulded case circuit breakers for protection and isolation of the PV, BESS, and diesel generator (if included). The switchboard will connect to the grid via a step-up transformer and an automatic recloser.

7.6 Control and monitoring

The control system will manage the following:

- Diesel dispatch
- BESS operating mode
- Centralised PV curtailment
- Embedded generation management
- Demand response
- Black start of the islanded microgrid
- Re-sync of centralised generation with the grid supply

The monitoring system will enable visualisation and data logging of:

- Power flows
- Isolation/protection device status
- BESS charge/discharge capability
- BESS state-of-charge/energy
- Power quality parameters

8 Project Impact

8.1 Social impacts

8.1.1 Socio-economic

Kimba

Kimba is within one of the major wheat producing areas in South Australia. It is known for its tourist attractions and as a nature destination with nearby conservation parks and reserves.

Census data in 2016 indicates Kimba has a higher proportion of its population in the labour force (66.9%) compared with average national levels (60.3%). However, the results also indicate that, compared with average levels in Australia, Kimba has a smaller proportion of high-income households earning $2,500 per week or more and a higher proportion of low-income households earning less than $650 per week. The agriculture, forestry, and fishing sectors employ 45.0% of the resident population in Kimba, in comparison, the sector employs 2.5% of the resident Australian population.

The 2016 census data shows a larger proportion of households in Kimba privately own their dwellings (46.7%) compared to the national average in Australia of 29.6%.

Population decline and limited economic growth pose problems to business and services to the community. The current development of a national facility to store radioactive medical waste on land 24 kilometres west of Kimba is an example of an infrastructure project to help diversify Kimba's primarily agricultural economy.

According to the District Council of Kimba, the reliability and quality of electricity in Kimba has made it difficult to attract new business. Increasing the reliability of electricity supply would make the town more attractive for residents, business, and visitors.

Koonibba

Koonibba is within the local government area of Ceduna which has a decile 4 rating for the Australian Bureau of Statistics Socio-Economic Indexes for Areas (SEIFA) of relative disadvantage (a decile rating of 1 to 10 where decile 1 is the most disadvantaged).[14]

Koonibba and other fringe-of-grid indigenous communities experience additional layers of disadvantage and reduced social outcomes when compared to urban centres, when electricity is not affordable or reliable. These communities are often underserviced by commercial, retail and recreation infrastructure, and when electricity is not available, there are no alternative services and amenities.

[14] 2033.0.55.001 Australian Bureau of Statistics, Socio-Economic Indexes for Australia, 2016.

Reliable and affordable electricity supply allows lighting, security, refrigeration, cooling, and heating can help to address multiple levels of socio-economic disadvantage by:

- Relieving cost of living pressures.
- Improving health and education outcomes – access to local medical services that require reliable power such as dialysis treatment, hot water for bathing, air-conditioning, and providing a safe and comfortable environment for children to learn
- Supporting reliable telecommunications networks by providing access to computer networks, data services, mobile phone services
- Providing more reliable access to on-line services including banking, tele-health services, on-line training opportunities
- Ensuring that safe and reliable water and wastewater processing services are available for the community

Improving access to modern electricity services for low-socioeconomic groups is essential for achieving good outcomes in the areas of employment, health and well-being, education, clean water and sanitation, and sustainable communities.[15]

Koonibba provides a discrete case study of the costs of energy for people living in social housing across Australia. The unemployment rate is 15% compared to 7.5% for South Australia.[16] The high level of unemployment means people typically spend more time at home and are more likely to incur higher household electricity expenses associated with heating, cooling, and lighting than households where people go to work.

Around 45 houses are state-owned by HousingSA and 5 are owned by the Koonibba Community Aboriginal Corporation. Most houses were built in the 1980s and 1990s, and a few built post-2000.[17] The average age of housing stock is 32.4 years, have 3 or 4 bedrooms and the Koonibba Community Aboriginal Corporation manages the tenancy and maintenance of housing. Typically, tenants of social housing have little capacity or incentive to install energy efficient appliances such as air-conditioners or hot water systems.

Sceale Bay

Sceale Bay is a small coastal town with a population of 42 according to 2016 census data. The number of people in the town increases several-fold during peak summer holiday periods. It is known as an isolated holiday destination for fishing and outdoor recreation.

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[15] UN, United Nations Open Working Group proposal for Sustainable Development Goals. 2014.

[16] 2016 census data, Australian Bureau of Statistics https://quickstats.censusdata.abs.gov.au/census_services/getproduct/census/2016/quickstat/SSC40707?opendocument

[17] Davidson, J. et.al (2011), Australian Housing and Urban Research Institute Final Report No.167, Remote indigenous housing procurement: a comparative study.

Census data in 2016 indicates average household income of $550 per week, with an average of 1.8 people per household and all dwellings privately owned. The resident population is predominantly employed in the agriculture, forestry and fishing and accommodation and food services sector.

8.1.2 Health and education

There are significant health impacts associated with irregular and sustained power outages. Reported impacts from the blackouts on the Eyre Peninsula in 2019[18] included:

- The inability to use medical equipment such as breathing assistance and dialysis machines.
- The inability to keep refrigerated medications cold.
- For properties not connected to mains water, the loss of water supply resulting in no water to drink, wash, and flush toilets.
- Aged care services impacts.

Improved energy reliability also has positive education outcomes. It enables learning in an air-conditioned environment, which is important to attendance rates as high temperatures can lead to school closures in the absence of adequate cooling. It is also essential for reliable internet access to online curriculum and resources, which are vital to geographically isolated communities.

Kimba

Kimba has a higher than national average proportion of its resident population in all the following age categories - older workers and pre-retirees (aged 50-59), empty nesters and retirees (aged 60-69), seniors (aged 70-84) and elderly aged (aged 85 and over).

The main health services in Kimba are:

- Kimba District Hospital, which provides general medical, post-surgical, palliative care, rehabilitation, and basic x-ray services
- Eastern Eyre Health, which is an assisted aged care facility, co-located with Kimba District Hospital
- Eastern Eyre Medical, which provides general practice services

The District Council of Kimba has previously expressed concerns about the impact of electricity outages affecting the Kimba District Hospital and Eastern Eyre aged care facility, on health and wellbeing. These concerns led to investigations into the potential for microgrid deployment in Kimba at the pre-feasibility stage.[19]

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[18] RDAEP Survey of Eyre Peninsula blackouts May 2019.
[19] Solenergy Consulting and Eye Energy Systems, Kimba Energy Reliability (Small Scale) Study, January 2018.

The Kimba Area School services the Kimba township and students living within 60 kilometres of Kimba, catering for approximately 190 students from Reception to Year 12.[20] Reliable electricity enables learning in an air-conditioned environment, which is important to attendance rates as high temperatures can lead to school closures in the absence of adequate cooling. It is also essential for reliable internet access to online curriculum and resources, which are vital to geographically isolated communities.

Koonibba

The Ceduna Koonibba Aboriginal Health Service located in Ceduna is the main health service for the local population. It is co-located with Ceduna Hospital which provides emergency services and dialysis care. The region has a high proportion of residents over 65 with aged care a focus of health services.

Sceale Bay

In the 2016 census, the median age was 55 years. The township of Streaky Bay, which is 32 km away, provides the main service centre for health services including the Streaky Bay Hospital and Streaky Bay Medical Centre.

General reported impacts on health from the blackouts in the Eyre Peninsula region in 2019[21] included:

- The inability to use medical equipment such as breathing assistance and dialysis machines.
- The inability to keep refrigerated medications cold.

For properties not connected to mains water, the loss of water supply resulting in no water to drink, wash, and flush toilets.

8.1.3 Bushfire risk reduction

SAPN has assessed the feeders to Kimba, Koonibba, and Sceale Bay as having a high probability of failure and are in bushfire and corrosion risk areas.

The Eyre Peninsula is prone to extreme high temperatures during summer, high wind, and catastrophic fire conditions. The 2005 Black Tuesday bushfires on the Eyre Peninsula resulted in the loss of nine lives, burnt around 82,000 hectares and estimated damages of $41 million.[22] During the 2019-20 bushfire season there were fires at Duck Ponds, Lower Eyre Peninsula in November 2019 and Miltalie on Eastern Eyre Peninsula in December 2019 causing a loss of communications and power.[23] The risk of bushfires in South Australia is

[20] https://www.schoolchoice.com.au/kimba-area-school/ (Date accessed: 11/04/2022)
[21] RDAEP Survey of Eyre Peninsula blackouts May 2019.
[22] Climate Council, Be prepared: climate change and the South Australia bushfire threat, 2014.
[23] Government of South Australia, Independent Review into South Australia's 2019-20 Bushfire Season, 2020.

increasing with hotter, drier conditions and the fire season starting earlier in Spring and lasting longer into Autumn.

Based on research with CSIRO and insurers risk analysis, SAPN has assessed the Eyre Peninsula as high-fire risk and will turn off electricity supply to whole towns in the region to reduce the risk of bushfires under certain circumstances. Local generation capable of powering Kimba, Koonibba, or Sceale Bay when islanded would enable lines to be de-energised without loss of supply, thereby reducing overall bushfire risk.

8.2 Economic

8.2.1 Employment and training

The implementation of demand management, behind-the-meter solar, and the proposed project gives rise to a range of potential employment and training opportunities, as shown in Table 2.

Table 2: Employment opportunities from microgrid implementation

Element	Employment Opportunity
Construction, operation, and maintenance	Opportunities for direct employment including indigenous labour to undertake project construction works and maintenance.
Energy related skill development	Opportunities for creating career paths through upskilling and training community members in energy related skills including operation and maintenance of project components
Local primary production business stimulation	Opportunities for local businesses to operate without interruption, increasing their output and in turn their number of employees
Hospitality, tourism, and other services	Opportunities to maintain or increase services to holiday rentals, increased visitation resulting in more expenditure in local hospitality business. Ability to maintain EFTPOS, mobile and landline phones, cooking facilities and online business so business able to remain open. Less food spoilage.

The expected employment associated with development, construction, operation, and maintenance of an intermittent microgrid at each site is summarised in Table 3.

Table 3: Estimated direct FTE jobs supported at each project stage.

Site	Development & Procurement	Design & Contruction	Operation & Maintenance
Kimba	3 x FTE for 1 year	13 x FTE for 1 year	1 x FTE for 25 years
Koonibba	0.5 x FTE for 1 year	4.2 x FTE for 4 months	0.2 FTE for 25 years
Sceale Bay	0.4 x FTE for 1 year	2.8 x FTE for 4 months	0.1 x FTE for 25 years

8.2.2 Business confidence

Surveys conducted following electricity outages in the Eyre Peninsula in 2016 and 2019 by the RDAEP show customers have become accustomed to power outages. Around 35% of businesses responding to a survey in 2016 have purchased their own backup generators increasing the cost of business. The 2016 survey found over 60% of business respondents in District Council of Kimba were unable to operate their businesses for 24-48 hours following the electricity outage in 2016.[24] Other reported impacts included:

- Mobile and landline telecommunication blackouts
- EFTPOS and ATMs not operational, limiting transactions to cash-only
- Cessation of internet and mobile phone services to support business operations
- Loss of perishable stock impacting food and seafood industries due to freezer/chillers not operating
- Tourism industry unable to take bookings and loss of trade
- Water pumps not operational affecting farm operations and service providers reliant on bore/rainwater
- ~3 weeks to restore activity and for sales to return to normal levels prior to outages

The 2019 survey found 43% of respondents in the Eyre Peninsula were without electricity for 12-24 hours, 13% for 24-36 hours and 2% for over 72 hours, resulting in a median economic loss for business of $1,000-$2,500.

Employment opportunities occur from the simple ability of local businesses to operate and expand. Reliable and cost-effective electricity is an important input to tourism and associated sectors of hospitality and accommodation services.

Koonibba

Koonibba is emerging as a location for tourism including as the site of the space launch facility used to test rocket motors and loads.

Sceale Bay

Sceale Bay does not have any industry or significant commercial operations. The small size of the town and restricted accommodation keeps visitation and associated tourism and hospitality services low. The town previously had a caravan park and general store providing petrol, takeaway food, and fishing and camping goods, but this has closed.

[24] RDAEP Blackout Survey September 2016.

If these small businesses were operating, the town could have a greater potential to be a more significant tourist destination in the Streaky Bay region. Reliable and cost-effective electricity is an important input to tourism and associated sectors of hospitality and accommodation services. The confidence of a reliable electricity service could encourage local businesses to operate and expand, contributing to local employment opportunities.

8.3 Emissions reductions

Scope 2 emissions from electricity consumption are proportional to the emissions intensity of electricity production on that grid. Transitioning to a renewable supply eliminates these emissions.

The emissions intensity on the South Australian grid is already low and is declining as the state moves towards the SA Government target of 100% net renewables by 2030. We estimated the avoided emissions attributable to the intermittent microgrid project by projecting the emissions intensity of the South Australian grid in line with this target.

Assuming the first year of project operation is 2025, ITP calculated the annual forecast annual greenhouse emissions attributable to each site under a business as usual, and project scenario. In all cases, the local RE completely offsets local emissions and exports the remaining clean energy back to the grid, leading to “negative” annual emissions. The total emissions offset for each project is summarised in Table 4.

Table 4: Forecast emissions reductions achievable with each proposed project.

Year	Kimba (tCO_2-e)	Koonibba (tCO_2-e)	Sceale Bay (tCO_2-e)
2025	535	54.4	27.1
2026	333	35.4	17.5
2027	195	21.3	10.5
2028	129	13.9	6.9
2029	65	7.0	3.5
2030	0	0.0	0.0
Total	**1,257**	**132**	**65.5**

9 Financial Analysis

9.1 Cost estimates

ITP estimated the costs a private developer and operator would be expected to incur across each stage of a proposed microgrid project. The three stages were assumed to be:

- Project development
- Design and construction
- Operation and maintenance

Development costs cover all activities up to signing of an engineering, procurement, and construction (EPC) contract for the design and construction of the proposed system. The design and construction stage covers all activities from EPC engagement up to Practical Completion. The estimated costs for each stage are shown in Table 5, Table 6, and Table 7 for Kimba, Koonibba, and Sceale Bay respectively.

Table 5: Project costs for the Kimba intermittent microgrid

Item	Price	Comments
Development & procurement	$810,000	Network connection studies and fees, development studies, concept design, and tender process.
Design & construction	$19,000,000	Project management, contract administration, owner's engineer, site studies and establishment. Design and construction of PV, BESS, grid connection, comms, control, and protection systems.
Project operations	$250,000 / yr	Administration, site operations, insurance, energy and LGC trading, and lease.
Replacement	$4,700,000	PV inverter, BESS inverter, and battery module replacement. All at expected end-of-life in year 15.

Table 6: Project costs for the Koonibba intermittent microgrid

Item	Price	Comments
Development & procurement	$88,000	Network connection studies and fees, development studies, concept design, and tender process.
Design & construction	$4,300,000	Project management, contract administration, owner's engineer, site studies and establishment. Design and construction of PV, BESS, grid connection, comms, control, and protection systems.
Project operations	$53,000 / yr	Administration, site operations, insurance, energy and LGC trading, and lease.
Replacement	$2,600,000	PV inverter, BESS inverter, and battery module replacement. All at expected end-of-life in year 15.

Table 7: Project costs for the Sceale Bay intermittent microgrid

Item	Price	Comments
Development & procurement	$83,000	Network connection studies and fees, development studies, concept design, and tender process.
Design & construction	$1,700,000	Project management, contract administration, owner's engineer, site studies and establishment. Design and construction of PV, BESS, grid connection, comms, control, and protection systems.
Project operations	$38,000 / yr	Administration, site operations, insurance, energy and LGC trading, and lease.
Replacement	$970,000	PV inverter, BESS inverter, and battery module replacement. All at expected end-of-life in year 15.

9.2 Revenue estimates

The intermittent systems will operate as a NEM generator while connected to the grid. ITP expects the systems will generate revenue by participating in the energy market, the FCAS market, and by selling LGC's.

9.2.1 Energy/FCAS market revenue modelling

The expected revenues from energy sales and FCAS participation were quantified using ITP's in-house BESS simulation model. This is a linear optimisation program that simulates energy and financial flows given price signals and technical constraints (e.g. PV availability, BESS state-of-charge, BESS capacity, export constraints) during each half hour of a 25-year analysis period. The model returns half-hourly energy flows and summary financial statistics.

PV generation is an exogenous variable in the model, derived by PVsyst. BESS charge/discharge is endogenous to the model. The BESS can bid into select FCAS markets, and the model decides whether to charge, discharge, or allocate capacity for FCAS to maximise value. The cost of charging from the grid comes from two sources, the wholesale price of energy, and network use of services (NUOS) charges.

9.2.2 LGC revenue modelling

ITP assumed LGCs were created according to the net energy exported from the connection point. The net energy exported is reduced by limits on the capacity of the upstream network and electrical energy losses in the BESS.

LGC prices were assumed to decline steadily until 2030. Post-2030, ITP assumed a small residual value for accredited renewable energy, potentially available via an extension to the Renewable Energy Target, or an equivalent carbon scheme.

9.3 Financial benefits to SAPN

9.3.1 Bushfire risk reduction

The CSIRO has conducted extensive modelling on potential damage from bushfires to quantify the financial consequences of fires started by SAPN's network. The modelling quantified the excepted loss per ignition calculated across all fire weather conditions and considered rates of successful early suppression by firefighters. The costs account for loss of life and property damage.

Decommissioning power lines removes the risk of electrical fires along that corridor. The consequence value is not distributed evenly throughout the year however, and a substantial portion can be avoided by de-energising segments of the network on high-risk days. Table 8 summarises the risks that can be avoided using an intermittent microgrid at each site. The value of the avoided risk was brought into present terms using a discount rate of 2.9%.

Table 8: Estimated bushfire risk-weighted consequence that can be avoided for each project

Project	Annual avoided risk	25-year NPV
Kimba	$30,252	$525,701
Koonibba	$5,998	$105,617
Sceale Bay	$0	$0

9.3.2 Reliability

SAPN uses an in-house algorithm to calculate the potential financial consequence of outages by tracing the network from point of failure to the nearest upstream protection device and then identifying all impacted customers. This method uses historical consumption data and expected rectification times to quantify the value of customer reliability.

The value of backup power provided by each proposed project was quantified by calculating the expected annual reduction in lost VCR. The results are summarised in the Table 9 below and brought into present terms using a discount rate of 2.9%.

Table 9: Estimated VCR benefit that can be realised for each project

Project	Annual VCR benefit	25-year NPV
Kimba	$53,906	$950,161
Koonibba	$18,801	$331,063
Sceale Bay	$6,389	$111,965

9.4 Summary

Direct project costs and revenues were compared from the perspective of a private sector investor with a weighted average cost of capital of 7.5%. The results of the cost benefit analysis for a 25-year analysis period are shown in Table 10 below.

Table 10: Summary of the financial cost benefit analysis results by scenario

Parameter	Kimba	Koonibba	Sceale Bay
Capex[25]	$19m	$4.3m	$1.9m
Opex ($2023 p.a.)[26]	$0.25m / year	$0.05m / year	$0.04m / year
NPV of all project costs	$25m	$6.1m	$3.1m
NPV of energy/FCAS market revenue	$14m	$0.94m	$0.55m
NPV of LGC revenue	$2.1m	$0.13m	$0.056m
Project NPV	-$9.1m	-$4.9m	-$2.5m
Project IRR (unleveraged)	0.36%	-11%	-16%

The results suggest that these projects will not pay back over a 25-year lifetime, without additional subsidy. There are several factors that contribute to this result, including:

- The size of each project is insufficient to achieve the economies-of-scale that larger PV and BESS projects competing in the same markets can achieve
- The export constraint imposed by the local distribution network results in curtailment
- Unlike larger BESS located near transmission substations, these BESS will be unable to access all FCAS markets and associated revenues

The indirect financial benefits to SAPN associated with the project proceeding include the reduced bushfire risk and improved reliability for their customers. However, the magnitude of these benefits is not sufficient to offset the projected financial loss of the project, suggesting it is unlikely that SAPN could offer a sufficient incentive to attract a project developer. Each project is also expected to avoid a modest volume of emissions over its lifetime. However, even at a high carbon price, this is insufficient to materially impact the economic case.

[25] Development costs, plus design and construction costs
[26] Recurring operating costs, excluding equipment replacement

10 Conclusion

This microgrid feasibility study found that intermittent microgrids powered by local PV and BESS are technically feasible in Kimba, Koonibba and Sceale Bay, and would increase electricity supply reliability, decrease bushfire risk, and reduce emissions. The AER's regulatory framework does not prescribe the governance of intermittent microgrids when islanded, presenting some issues, but they are typically permitted if islanding is infrequent.

Nevertheless, without additional subsidy, the financial case for these intermittent microgrids is weak. Our analysis suggests that the projects will not pay back over a 25-year lifetime. There are several factors that contribute to this result, including:

- The size of each project is insufficient to achieve the economies-of-scale that larger PV and BESS projects competing in the same markets can achieve
- The export constraint imposed by the local distribution network results in curtailment
- Unlike larger BESS located near transmission substations, these BESS will be unable to access all FCAS markets and associated revenues

The projects would deliver additional benefits to SAPN including reduced bushfire risk and improved reliability for their customers. However, the magnitude of these benefits is not expected to be sufficient to offset the financial losses of the projects, suggesting it is unlikely that SAPN could offer a sufficient incentive to attract a project developer.

A detailed quantitative economic assessment (correcting market prices for distortions, accounting for externalities, etc.) is outside the scope of this report, but ITP expects that such an analysis would return a negative NPV owing primarily to the following:

- The emissions intensity of South Australia's NEM is low and falling.
- The extent of the outages that would be mitigated by the project is relatively low.
- The extent of the bushfire risk that would be mitigated by the project is relatively low.
- The financial factors described above.

While other DNSPs have identified attractive back-up power projects in Australia, alternative projects such as a SAPN-owned BESS (or diesel gensets) for back-up power provision to Kimba, Koonibba and Sceale Bay are also unlikely to be financially attractive at these locations given the low costs associated with outages and bushfire risk.

Screening Study

Microgrids & Individual Power Systems

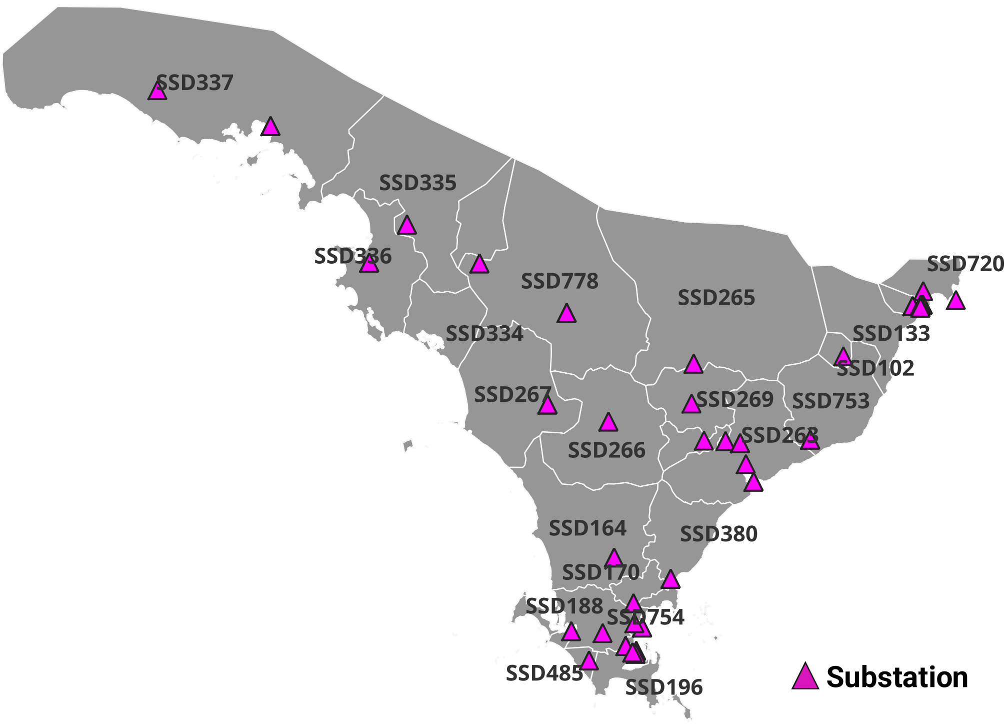
1 Methodology

The screening tool study procedure can be broken down into five steps:

1. An initial assessment of the scope of input data and processing required.
2. Data collection and pre-processing.
3. Creating a mathematical representation of the Eyre Peninsula distribution network.
4. Estimating unit costs for modifications to the current network including new microgrid builds, upgrades, and maintenance.
5. Ranking possible future configurations of the distribution network using relevant metrics.

1.1 Initial Assessment

Zone-Substation layer



The SAPN distribution network in the Eyre Peninsula is partitioned into 28 zone-substations (ZS) labelled by a unique substation district (SSD) identification number. Each zone has one or more substation junctions which act as a distribution point to all assets within that zone. Substations that supply a particular zone are typically found within that zone, however, there are exceptions such as SSD334.

Asset Data

Two data sets were provided which include geospatial and metadata information, for assets within the SAPN. The data frames each have 191,358 assets covering over 40 categories of components. Most component types are used in all zones within the Eyre Peninsula. Additionally, the geospatial representation and abundance of each asset is detailed enough to generate highly connected networks across each of the ZS. However, the network objects are not fully connected which indicates that there are gaps within the asset data. Further pre-processing was conducted to ensure that there was always a geospatial path between each asset within the network.

Bushfire Risk

The bushfire risk data set provided by SAPN provided risk costs under different bushfire scenarios using data provided by CSIRO. The data set includes Current Total Risk and Extreme Catastrophic Estimates. The dataset covers 122 distribution feeders within the SAPN which is less than the number of feeders covered in the assets data set with a total of 183 unique feeders. This indicates that the bushfire data set covers only 67% of the total assets provided. The reason for missing feeders has been attributed to that fact that these feeders do not lie in medium or high bushfire risk areas and therefore bushfire modelling for these areas was not completed. SAPN has indicated that in other applications of this bushfire modelling, these areas have been considered to have no bushfire consequence. Further pre-processing will include extrapolating data for missing feeders in areas where data exist for nearby feeders.

Distribution Risk

The distribution risk data set provided by SAPN covers five different consequence categories including reliability, safety, financial, environmental and bushfire. These consequence risks were forecasted in 2021 and therefore the bushfire and reliability data has been superseded by updated datasets which will be used for analysis and modelling. The distribution risk dataset covered 8 different asset categories. The dataset also includes assets not found in the assets data set such as poles and switching cubicles.

O&M Risk

The O&M data provided by SAPN includes annualised O&M data for different ZS within the Eyre Peninsula. The data covers six substation zone including Ceduna, Streak Bay, Wudinna, Cleve, Cummins, and Port Lincoln.

VCR

The VCR data provided by SAPN includes aggregated risk at a protection device level showing the risk associated with upstream assets if they were to have an outage. The protection devices have been aggregated at a feeder level.

Overall Coverage

With all datasets it is possible to cover 22 of the 28 ZS across the Eyre Peninsula. The timing of the analysis did not permit the inclusion of data from the VCR and O&M datasets situated across the Whyalla and Wudinna regions. The missing ZS include: SSD337, SSD720, SSD793, SSD217 and SSD133. The following figure illustrates the zones that are highly covered by the data and will be analysed in the screening tool study.

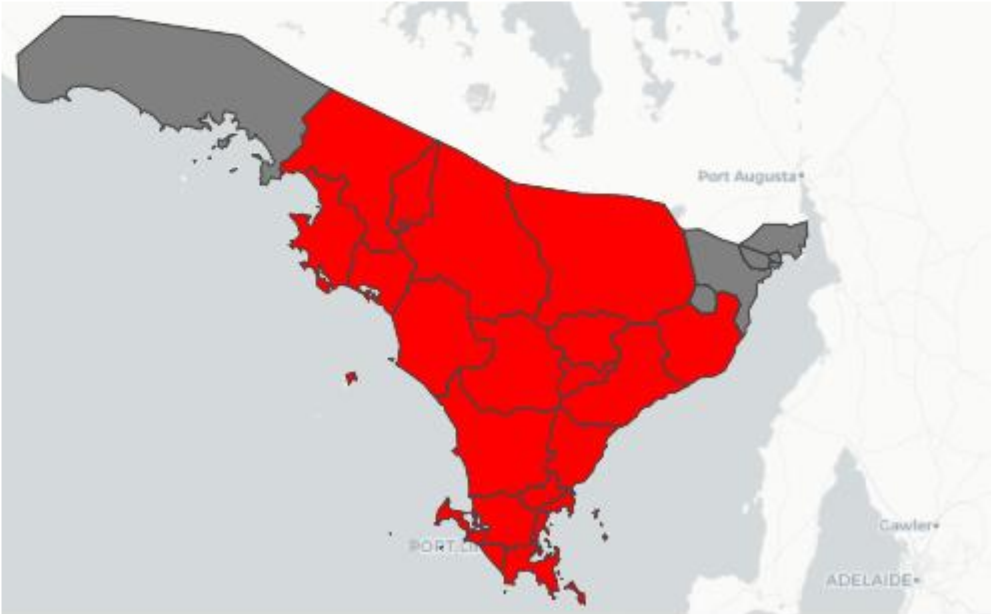


Figure 34: Zones fully covered by provided data

Additionally, SSD102 is in the North zone of the Eyre Peninsula which includes an islanded portion of the SAPN. This location was found to be occupied by SIMEC in the southwest of Whyalla. This region will not be considered for analysis due to limited data and the highly specific customer arrangements used for mining operations.

1.2 Data Collection and Pre-processing

1.2.1 Network Components

SAPN provided a comprehensive dataset of physical elements within the Eyre Peninsula distribution network (the Network). This covered over 40 categories of components, and included a unique ID and geographical representation of each component (as a point, line-string, or multistring), the component's category, and other metadata such as voltage ratings, junction size, etc.

Connecting Elements

Pre-processing of this data revealed that the Network could be represented using a simplified set of connected elements that ensured enough resolution to provide accurate cost assessments at the individual customer level, without requiring a supercomputer for consequent processing.

1.2.2 Financial Risk

Reliability

SAPN provided Value of Customer Reliability (VCR) data, which attributes a total cost to SAPN per hour of an outage at given protection devices within the Network.

Bushfire

SAPN provided bushfire risk data representing the cost to them of a bushfire occurring along particular HV feeders. The Extreme Catastrophic Estimate and the current Total Risk were taken, which represent the cost of network components being completely removed, or switched off, during high-risk bushfire days.

Operation and Maintenance

SAPN provided other human safety and environmental risk data for the following elements in the Network:

- Cables
- Overhead conductors
- Poles
- Reclosers
- Sectionalisers
- Service lines

The likelihood and cost to SAPN of each risk occurring were used to get a weighted cost for each risk, for each element. O&M estimates for HV cables were provided by SAPN for Ceduna, Streaky Bay, Wudinna, Cleve, Cummins, and Port Lincoln, per 100m span per year.

Load and Generation Profiles

Hourly load data for each substation was provided by SAPN, and this was processed using relative annual transformer loads to get a higher resolution distribution of load across the Eyre Peninsula. Solar energy, as daily Global Horizontal Irradiation (GHI), for 1990–2022 was calculated using satellite imagery. Wind energy is not included in this analysis as it is impractical and financially inviable at the scales considered in this analysis.

1.3 Graph representation of the distribution network

Graph theory is the study of mathematical structures that represent pairwise relations between objects. A graph consists of points, termed *nodes,* connected by lines or *edges* to create a network of connected elements. A set of edges between a set of nodes is called a *path*. Edges are usually given a *weight*. Weights enable us to find the shortest path between two nodes: in our Network this is the distance between two points in kilometres.

By combining GIS data, clustering, and graph theory, it is possible to provide a high-level abstraction of the distribution network within the Eyre Peninsula which can be exploited for modelling purposes.

The connecting components identified in pre-processing (e.g. HV lines, reclosers and switches) were used to construct the edges of the Network graph representation, and the transformers identified in pre-processing were used as nodes.

1.4 Pre-screening

A number of different methods for filtering and arranging the Network arithmetically were used to reduce computation and provide insight into the problem to guide our approach further.

1.4.1 Meshed and Radial Sections

Most distribution networks can be described as *meshed* or *radial*, depending on the presence of *loops*. A network loop occurs when a there is more than one route from one node to another. As in Figure 35, a radial network is tree-shaped with no closed loops. This kind of topology is the simplest and cheapest for a distribution network, but if a line is disconnected, those downstream also lose power. This type of structure is typically found in rural areas.

In a meshed network, loops allow power to be delivered through multiple routes connected to each other, making a mesh. This topology is more reliable with lower losses but requires significantly more infrastructure and investment. It is typically found in urban parts of a power network.

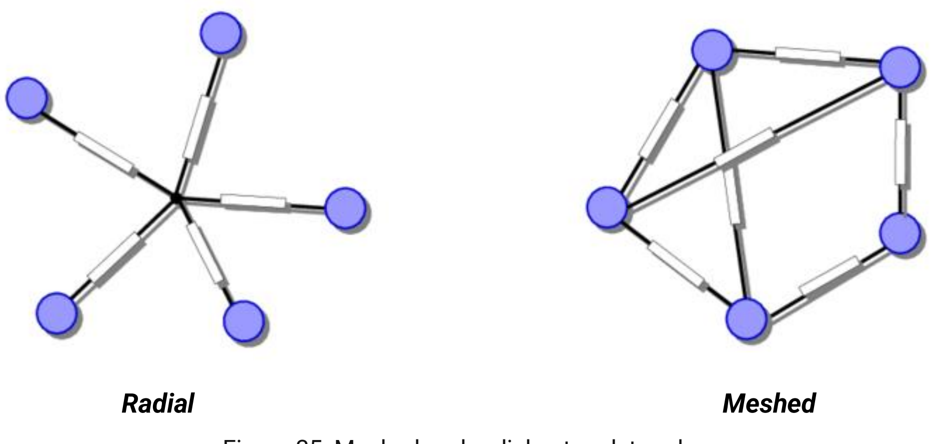


Figure 35: Meshed and radial network topology

Pre-screening revealed that meshed portions of the network are not viable for conversion to microgrids, as they have high energy security due to multiple supply lines, and low financial risk due to proximity to maintenance services. Thus, for this study, we targeted radial sections of the network, as they have a much higher risk due to lack of redundancy, and a tendency to have longer stretches of single lines that are used by only a few customers.

1.4.2 Branch Traversal and Permutations

The branch traversal algorithm utilises data and geospatial information obtained in previous steps to traverse the network from the outermost points towards the centre.

When traversing, the algorithm will store the details of visited assets when it reaches a junction point. This group of unique IDs is classified as a *permutation* of the network, as it represents a unique group of assets downstream of an asset at any given point of the Network.

As metadata is attached to each unique asset it is possible to find the total sum of risks or costs associated with a particular permutation. These risk and capital costs are used to calculate the outcome of an objective function, described in the following section.

The screening tool traverses the entire network using the process described above.

1.5 Calculation of Financial Return

Net Present Cost (NPC)

A detailed model for multiple load size ranges was developed for each Zone Substation. This outputs a microgrid or IPS design incorporating PV, BESS, generator, and PCS architecture with calculated NPC, CapEx, and OpEx. A discount rate of 2.9% was applied and the projects had a lifetime of 25 years. A minimum renewable energy fraction of 90% was also applied as a constraint.

Replacement and O&M costs for microgrids and IPS are accounted for in this cost modelling, and the reliability of both is assumed not to be a risk due to built-in redundancy in IPS systems, and the very low chance of a microgrid and the distribution network failing simultaneously.

For microgrids, the capital cost of a switch is included, used when isolating a microgrid system during network events. The cost of a switch was annualised over a 5-year period with a 2.9% WACC.

Objective Function

An objective function is a mathematical expression used to represent the goal of an optimization problems. By changing variables within the objective function, it is possible to find an optimised solution. In the context of this project, an objective function is used to relate all risk and capital cost variables used in different scenarios to analyse whether network disconnection or decommission is feasible.

There are two scenarios for which objective functions were generated for each unique permutations within the power network of the Eyre Peninsula. The two scenarios considered are the switching off a portion of the network and replacing it with a microgrid, and the complete disconnection and decommissioning of existing grid assets, replaced by household Individual Power Systems (IPS).

All the above financial risks and benefits were included in objective functions for IPS and microgrids, used to produce the results of the screening study, in combination with the network traversal algorithm.

2 Screening Results

The screening tool developed for this study was used to conduct a study across each Zone Substation (ZS) in the Eyre Peninsula. Within each zone, every way that the distribution network could be modified to install a microgrid or IPS systems was determined. For each of these permutations, the screening tool calculated the annual financial return to SAPN of making that modification compared to the existing network. This allows us to rank the best performing permutations according to the business requirements of SAPN.

We present the results of this screening study in 3 sections: IPS and Microgrids, BESS Cost Sensitivity and a Sensibility Study.

2.1 Financial Return

The total return of all permutations includes nested modifications that share assets and risks, for example, where a modification is downstream of another, larger modification. This value therefore cannot be realised. To present the real total opportunity to SAPN, we total all the discrete permutations with a positive return in each zone, shown in Table 11. This value could be realised if all the modifications associated with these permutations were implemented. A heatmap of these values is shown in Figure 36. Grey coloured areas do not have sufficient risk data to perform screening.

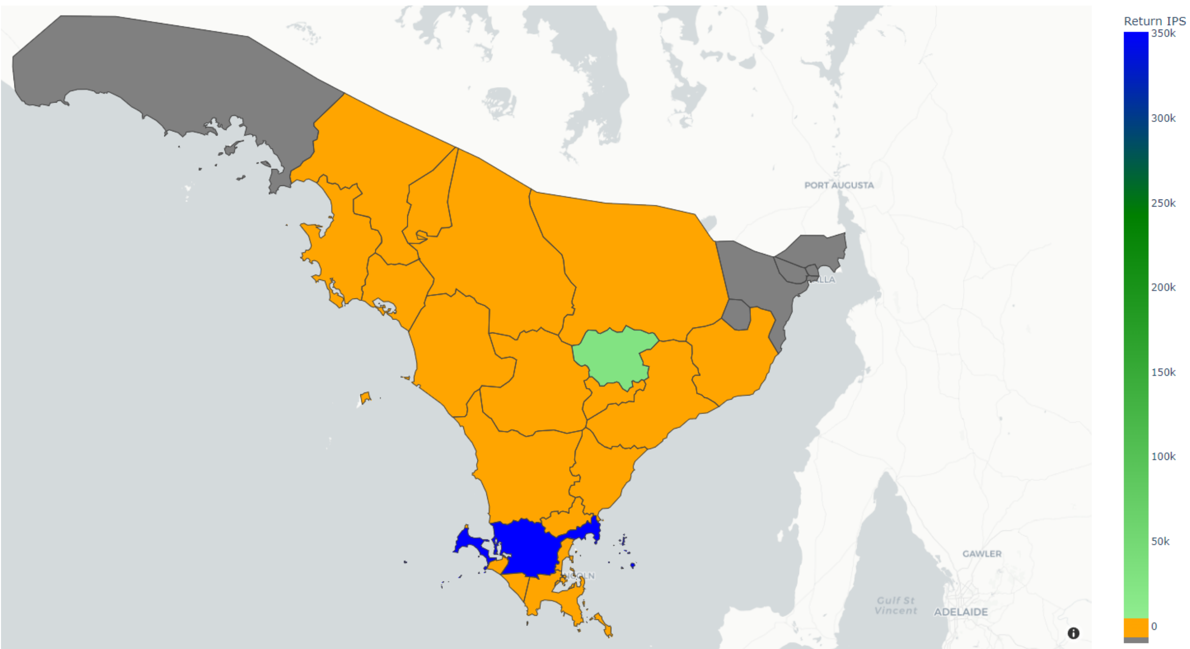


Figure 36: Heatmap of total annual return for discrete IPS permutations with positive return

SSD188 shows the highest annual return with a total of $349,242 across all discrete positive permutations within the zone. SSD269 shows a return of $27,266. All other zones show a return of $0 indicating all permutations are negative within these zones.

The total annual return of all discrete microgrid permutations with positive return is in Figure 37.

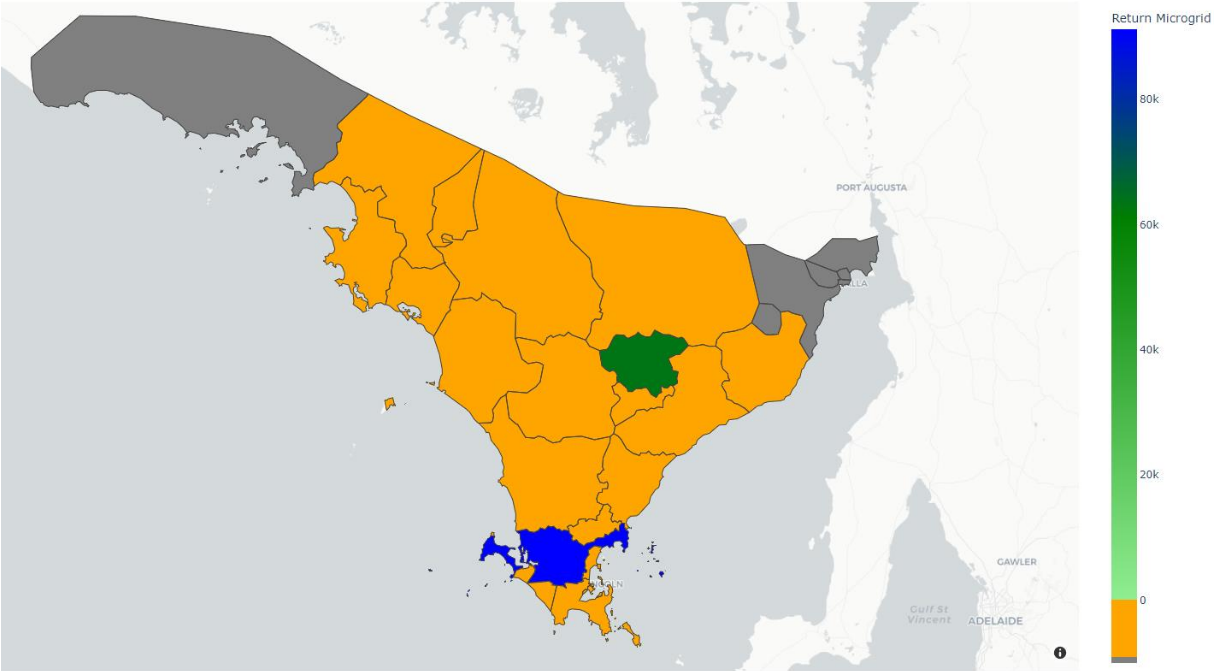


Figure 37: Heatmap of total annual return for discrete microgrid permutations with positive return

SSD188 and SSD269 are the only ZS that return positive permutations. SSD188 has a return of $88,888 with SSD269 showing a return of $63,334.

Based on these results, feasible permutations for both IPS and microgrids are found in the same zones with a higher return for discrete permutations in SSD188 for IPS and a higher return for microgrids in SSD269 (lower return shown in grey in Table 11).

Though microgrid permutations in SSD188 have positive returns, they cover areas that contain IPS permutations with much higher returns, so a better option is to use IPS. Additionally, IPS permutations in SSD269 have positive returns, but cover areas that contain microgrid permutations with much higher return, so a better option is to use microgrids. These considerations are included when calculating the total annual return across all discrete permutations showed in Table 11.

Table 11: Total annual return of discrete permutations with positive return

SSD ID	Zone Name	IPS ($)	Microgrid ($)
SSD164	Cummins	0	0
SSD170	Tod River	0	0
SSD174	Rudall	0	0
SSD188	Port Lincoln Terminal	349,424	88,888
SSD196	Port Lincoln City	0	0

SSD263	Cleve	0	0
SSD265	Caralue	0	0
SSD266	Lock	0	0
SSD267	Polda	0	0
SSD269	Darke Peak	27,266	63,334
SSD325	Port Lincoln Docks	0	0
SSD334	Moorkitabie	0	0
SSD335	Tarlton	0	0
SSD336	Streaky Bay	0	0
SSD380	Tumby Bay	0	0
SSD485	Uley South	0	0
SSD533	Coffin Bay	0	0
SSD753	Cowell	0	0
SSD754	Point Boston	0	0
SSD778	Wudinna	0	0
SSD803	Port Lincoln Marina	0	0
Total		**349,424**	**63,334**

Table 7 shows the number of service points covered by the discrete permutations found in Port Lincoln Terminal and Darke Peak.

Table 12: Number of service points covered by discrete permutations.

Zone	Number of Service Points covered	
	IPS	Microgrid
Port Lincoln Terminal	149	91
Darke Peak	55	71

2.1.1 Total Opportunity

As shown in Table 11, the total annual return to SAPN across all discrete permutations and all zones is $414,456. The Net Present Value (NPV) over the lifetime of these systems would be approximately $8 million, with a discount rate of 2.9%.

2.1.2 Ratio of Positive Returns

To show the proportion of permutations with positive returns, we calculate the mean return for each zone. A heatmap of the mean annual return for the IPS scenario by ZS is shown in Figure 38.

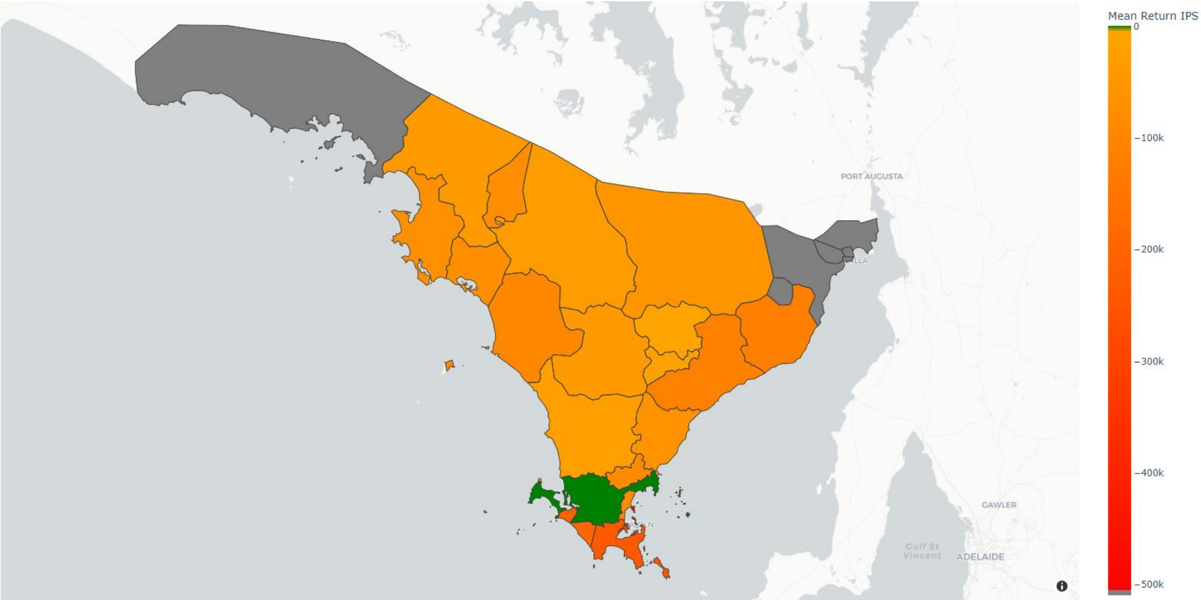


Figure 38: Heatmap of IPS mean annual return

The heatmap shows that ZS situated around the centre of the Eyre Peninsula have a smaller mean return in comparison to ZS situated along the coast towards the west, south and east. SSD188 has the highest mean return, with an overall positive return across all permutations within the zone, with SSD754 having the lowest.

A heatmap of the mean annual return for microgrids by ZS is in Figure 39.

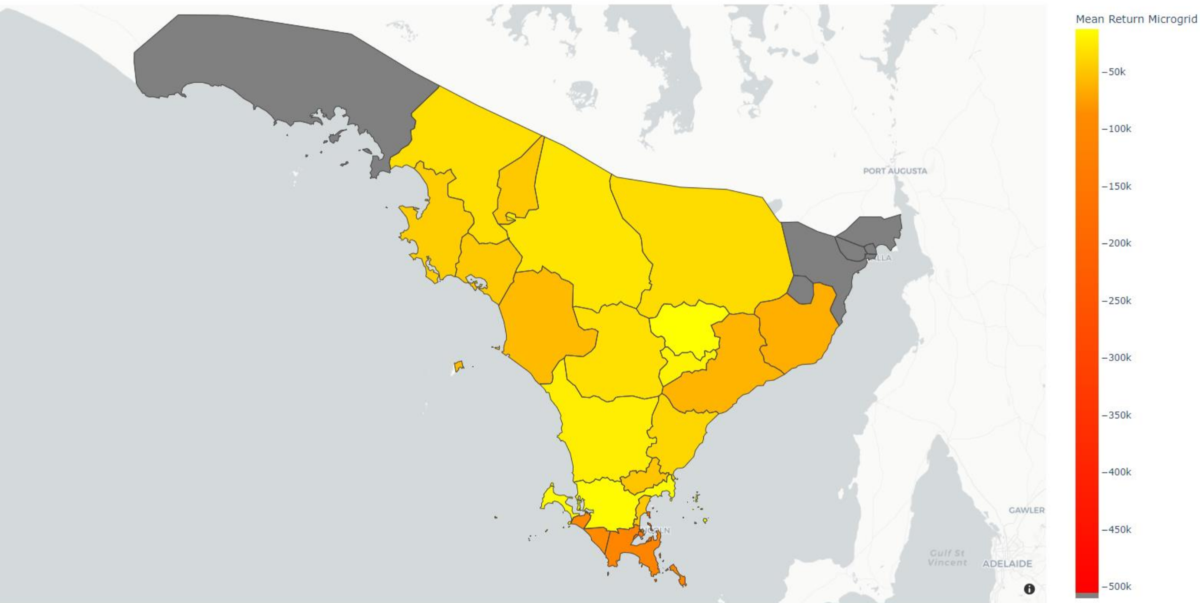


Figure 39: Heatmap of microgrid mean annual return

This shows that the mean annual return is uniform across most zones and mostly under $65,000, with a decrease in return towards the south of the Eyre Peninsula. Most zones have a negative mean return. Figure 19 shows no positive mean returns with SSD269 having the least negative mean return, followed by SSD188.

To visualise this comparison more clearly, Figure 40 shows the percentage of positive annual return across each ZS for both the IPS and Microgrid scenarios.

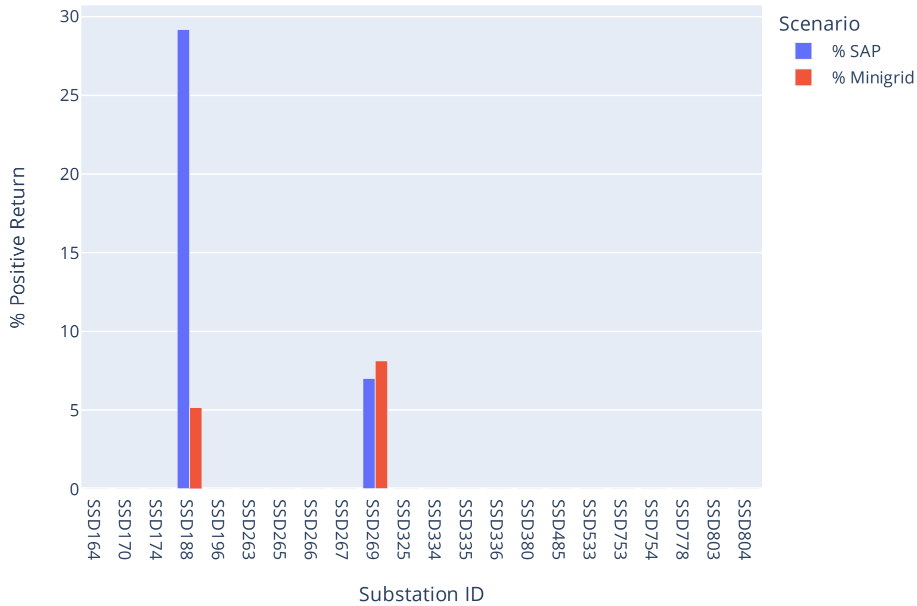


Figure 40: Percent of permutations with positive annual return

As expected, SSD188 and SSD269 both show positive return permutations across both scenarios. In SSD188, IPS have over 5 times the positive returns in comparison to microgrids with 27% of the permutations analysed in SSD188 being positive.

Additionally, Figure 41 shows the mean annual return of both IPS and Microgrid scenarios across all ZS.

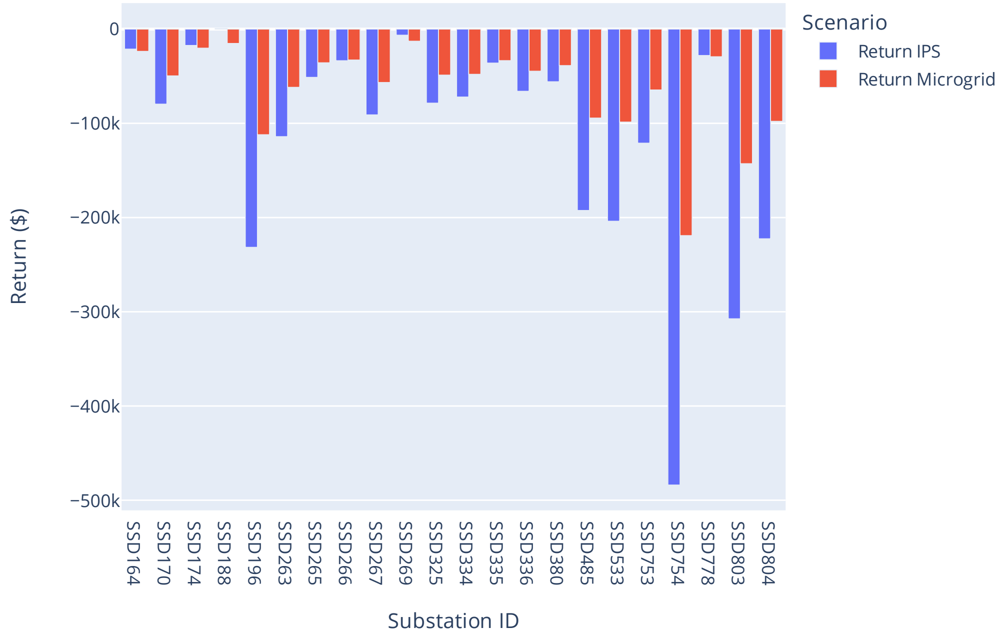


Figure 41: Mean annual return comparison

The mean return of the microgrids across all zones is negative, with the IPS scenario for SSD188 showing the only positive mean return. Even though most microgrid permutations across each zone have a less negative return, IPS overall have more positive returns. This is because the cost of implementation of a microgrid is cheaper than IPS, however, the risk associated with microgrid implementation does not adequately cover the capex associated with the system design.

2.1.3 Effect of Risk

Figure 42 illustrates how the total risk cost influences the return of the IPS scenario across its top 10 positive permutations.

Figure 42: IPS return vs. Total risk cost (top 10 permutations)

This shows that there is a consistent trend for permutations that show a negative return where the total risk is close to 0. This indicates that positive returns are highly reliant on the total risk associated with a given permutation. Furthermore, there is a clear positive trend between positive return permutations and total risk. In some cases, such as for SSD269, the positive trend between return and total risk approaches zero. This pattern can be attributed to smaller NPC values associated with the systems due to varying load sizes resulting in an increase in return with lower total risk. This also explains the large range of return seen between SSD174 and SSD188 for similar total risk values.

Figure 43 illustrates the total risk cost and the return of the microgrid scenario across its top 10 permutations.

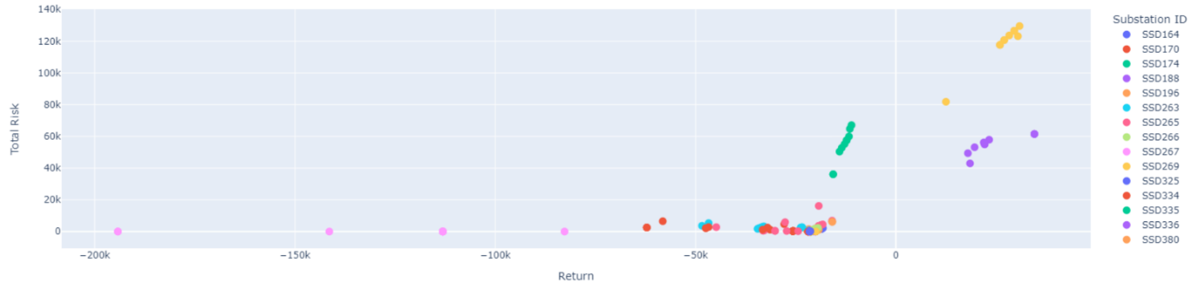


Figure 43: Microgrid return vs. Risk cost (top 10 permutations)

The microgrid scenario shows a positive trend between return permutations and total risk. Again, there is a trend for permutations that show a negative return whereby the total risk is close to 0. However, permutations for SSD174 show a negative or close to 0 return even though they have a large total risk. This further shows that the risk associated with a permutation is not large enough to account for the capital costs associated with microgrid implementation. It can also be seen that the size of the microgrid systems associated with SSD188 are a lot smaller than the systems found in SSD174.

Figure 44 and Figure 45 illustrate the total risk cost and the return for both the IPS and microgrid scenarios respectively, across their bottom 10 permutations.

Figure 44: IPS return vs. Risk cost (bottom 10)

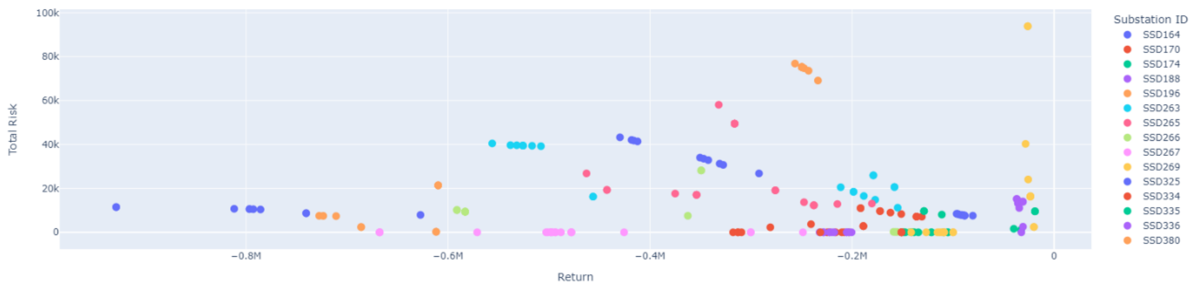


Figure 45: Microgrid return vs. Risk cost (bottom 10)

There is a weak negative trend between the risk cost and return of an IPS system. Most of the total risk cost for the IPS scenarios lie close to or below $100,000. Most of the total risk cost for the microgrid scenarios lie close to or below $20,000. In both scenarios, we do see a few zones lie outside these thresholds with much larger total risk, however, still having a negative overall return for a given permutation. In addition, most permutations close to $0 return have a similar total risk to permutations with large negative returns.

The explanation for the trends found in Figure 44 and Figure 45 is illustrated in Figure 46 which shows the cost contribution of different risk and NPC variables associated with the IPS scenario for the largest return permutation across each substation.

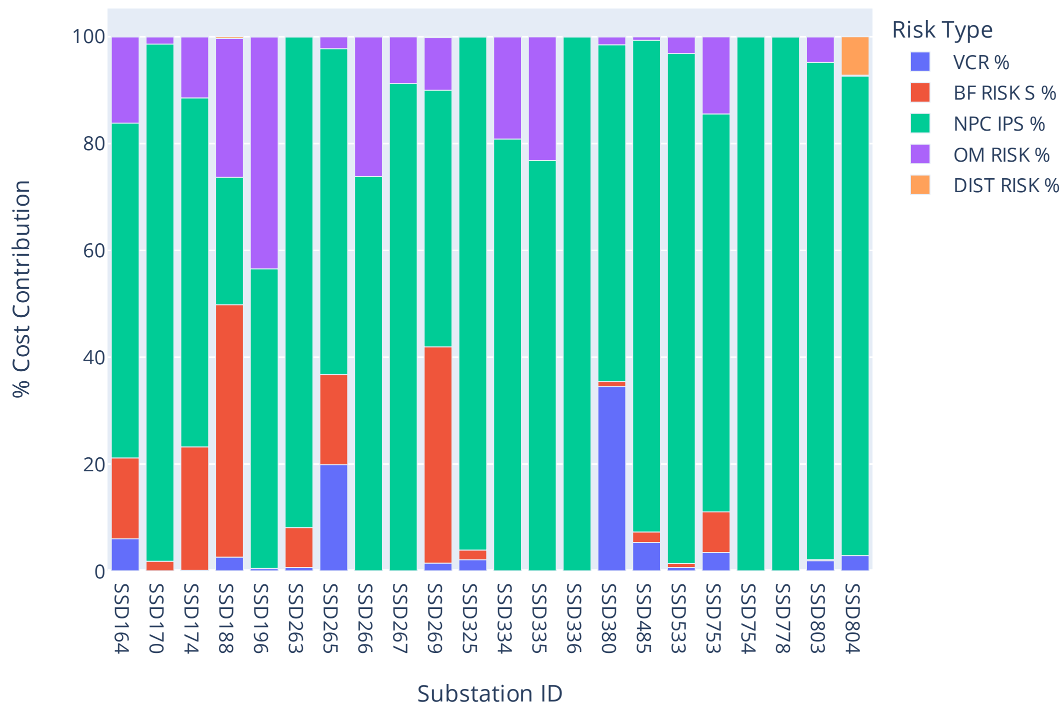


Figure 46: IPS risk cost contribution for largest permutation

The annual return of the best performing permutations for both scenarios can be seen in Table 13 for each substation, with positive returns highlighted.

Table 13: Annual return of the best performing permutations for each substation

Substation ID	Microgrid ($)	IPS ($)
SSD164	-2849.85	-18229.8
SSD170	-19866.2	-25586.3
SSD174	-4279.69	-11082.4
SSD188	80624.32	34573.67
SSD196	-4266.03	-20792.4
SSD263	-10866.5	-21644.9
SSD265	-4613.64	-15923.8
SSD266	-5668.53	-21069.5
SSD267	-5752.49	-20081.6
SSD269	15797.12	30860.51
SSD325	-6538.02	-20033.5
SSD334	-8102.24	-21860
SSD335	-6652.11	-21405.5
SSD336	-6264.34	-20040
SSD380	-4557.57	-15885.2
SSD485	-41087.9	-32966.4
SSD533	-9611.06	-21517
SSD753	-6859.47	-19450.1
SSD754	-156055	-82714.6
SSD778	-6075.99	-19961.5
SSD803	-9216.66	-21366.1
SSD804	-32,040	-66,462

Table 13 shows that the largest IPS return permutation is in SSD188. By observing Figure 46, the NPC of the IPS system accounts for less than 50% of the total cost contributions associated with that permutation. In this case, for a permutation to achieve a positive return, the risk must account for more than 50% of the total cost contribution. This relationship can be highlighted by looking at the most negative return found in SSD754. By observing Figure 46, the least negative permutation in that region has no risk cost. Therefore, the NPC of the

IPS system makes up the entirety of the return cost associated with that permutation. Furthermore, Figure 46 shows that the largest contributing factor across all risk variables is the bushfire risk with the smallest contributing factor being the distribution risk. Additionally, Table 13 shows that out of the 22 ZS, 9.1% of them have a permutation with a positive return. This indicates that 9.1% of the zones analysed contain permutations that could potentially be decommissioned and replaced with an IPS system.

Finally, the difference seen between SSD174 and SSD188 seen in Figure 43 can be explained by observing the contribution of the NPC of the IPS system. Both zones have shown to have similar total risk, however, SSD188 returns permutations with largely positive return values. This can be explained by the differences in NPC contribution shown in Figure 46, with SSD188 having an NPC contribution due to the smaller load size of the system.

Figure 47 shows the cost contribution of different risk and NPC variables associated with the microgrid scenario for the largest return permutation across each substation.

Figure 47: Microgrid risk cost contribution for largest permutation

Zones that showed a positive return in Figure 39 all have a total risk cost contribution greater than 50%. In comparison to the IPS scenario, all the ZS associated with the microgrid study show no risk contribution from O&M and distribution as they are not applicable to the objective function for the microgrid scenarios. Additionally, the bushfire risk is significantly reduced in comparison to the IPS scenario. Due the exclusion of these variables in the objective function, most permutations across all zones return negative. Additionally, Table 13 shows that out of the 22 ZS, 9.1% have microgrid permutations with a positive return.

These network sections could be disconnected and replaced with a microgrid and benefit SAPN and the customers connected to them.

2.2 BESS Cost Sensitivity

It has been found that the NPC of the microgrids and IPS plays a large role in whether a portion of the network is feasible for conversion. Based on this, it is important to determine whether variables comprising the NPC of these systems can be changed to enable larger cost returns of permutations. This section investigates the effect of BESS costs on the feasibility of each permutation.

Figure 48 shows the mean return of an IPS system with BESS cost between 30–100% of March 2023 costs across each ZS.

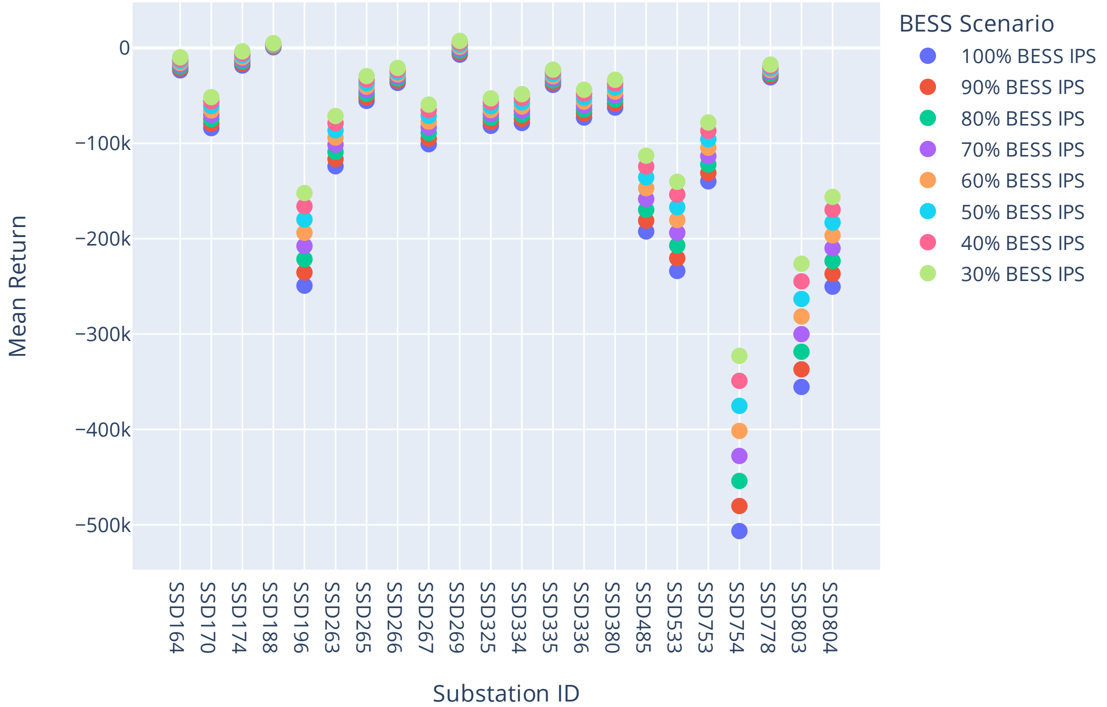


Figure 48: Effect of BESS cost on IPS mean annual return

This shows that there are several zones that will have a position mean return if BESS costs reduce. These zones include SSD188 and SSD269. SSD188 is shown to already have a positive mean return at 100% of the current BESS cost with at least a $800 return across all permutations.

Figure 49 shows BESS cost sensitivity for ZS that are closest to a positive return for the IPS scenario.

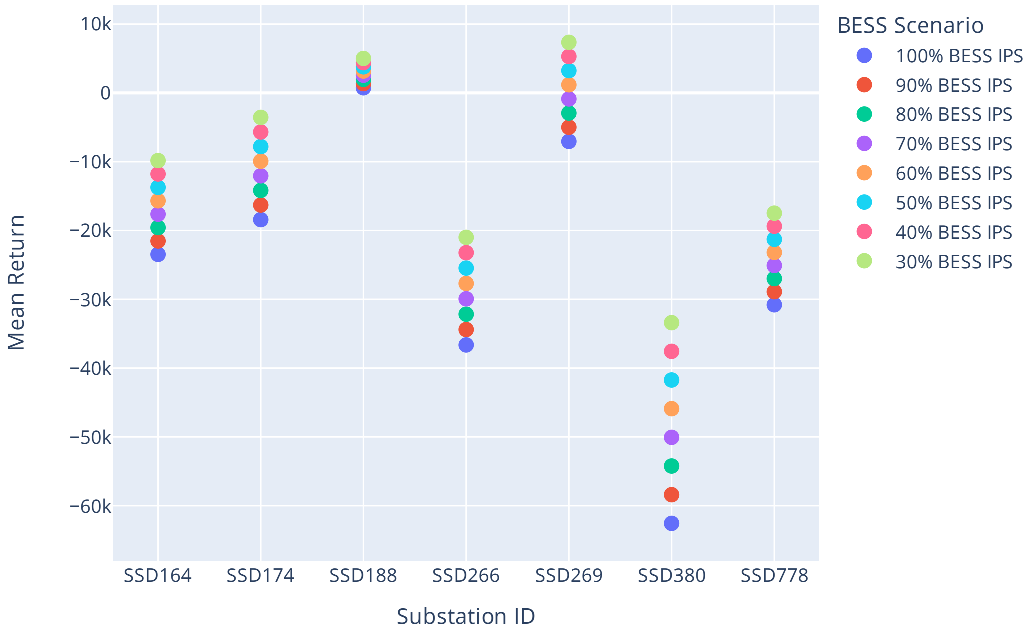


Figure 49: Effect of BESS cost on subset of IPS mean annual return

This shows that SSD188 and SSD269 will show an overall positive mean return at 100% and 60% BESS costs respectively. SSD188 shows a slight increase in the mean return as the BESS cost reduces. It is unlikely that BESS costs will reduce below 70% of current prices in the next several years, so SSD269 will not see a positive return if it is converted to IPS.

Figure 50 shows the mean return of a microgrid system with BESS cost between 30–100% of March 2023 costs across each ZS.

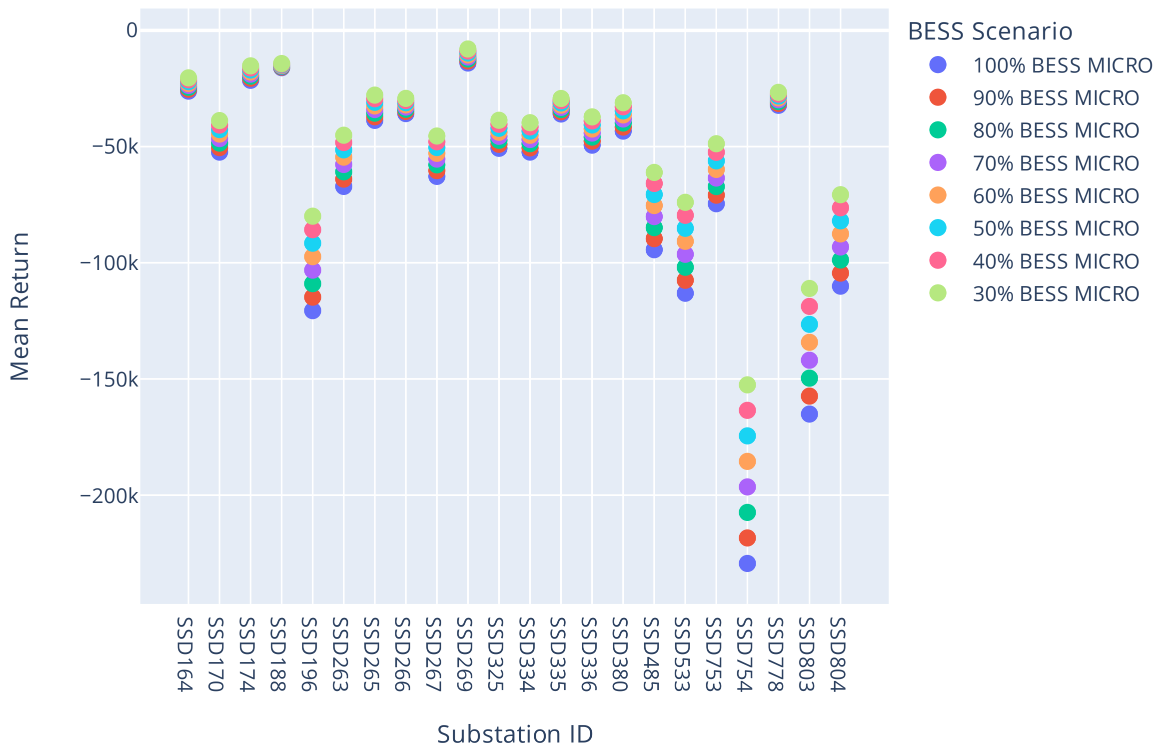


Figure 50: Effect of BESS cost on microgrid mean annual return

Across all ZS there are no scenarios for which a reduction in BESS cost will result in a positive mean return. In comparison to the IPS scenario, the microgrid objective function is less dependent on capex and therefore less susceptible to capex reductions.

Figure 31 shows the influence of IPS BESS reductions on the annual returns of discrete permutation sets.

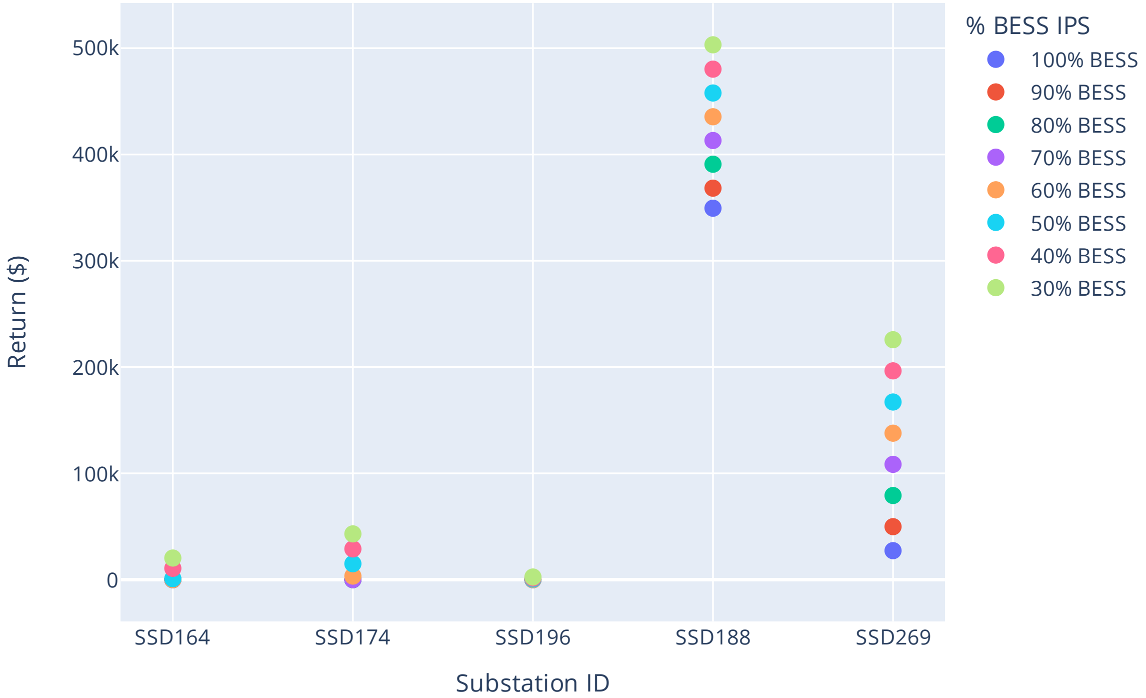


Figure 51: Effect of BESS cost on IPS annual return

SSD188 and SSD269 have been identified to have a positive annual return at 100% of current BESS prices. At 70% BESS prices, SSD188 shows a $63,692 increase in annual return and SSD269 shows a $81,199 increase in annual return.

SSD164, SSD174 and SSD196 show a positive return at 50%, 60%, and 50% BESS prices respectively. All other zones showed no positive return across all BESS reductions.

Figure 32 shows the influence of microgrid BESS reductions on the annual returns of discrete permutation sets.

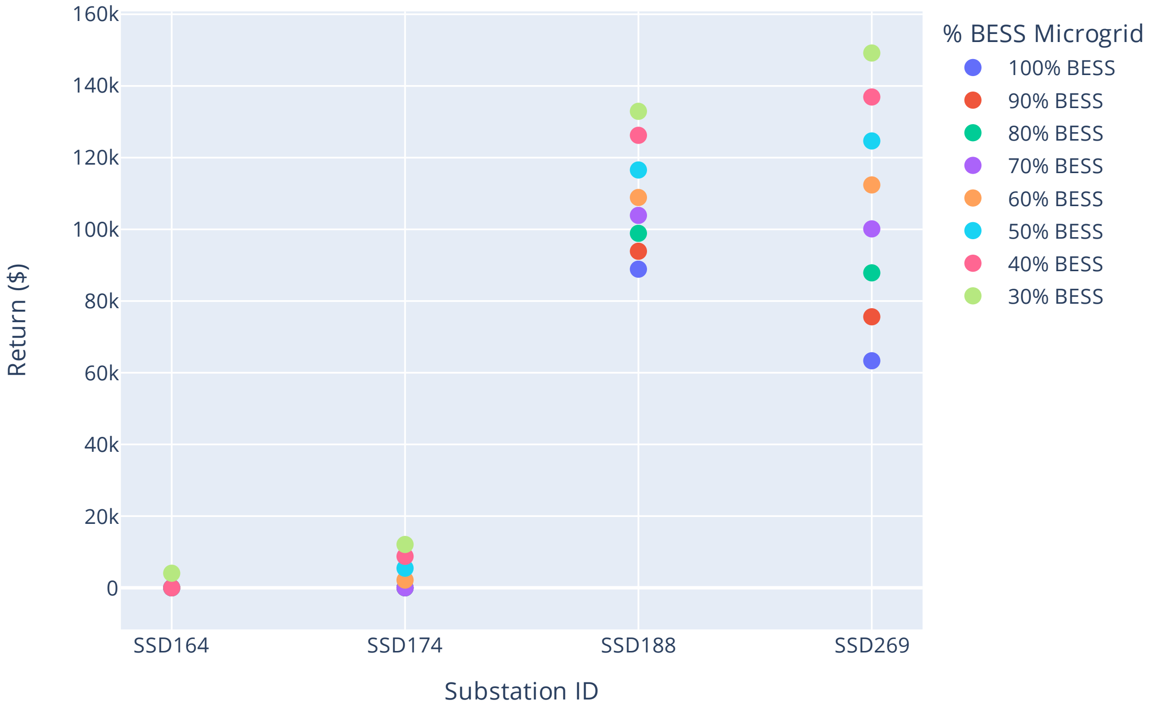


Figure 52: Effect of BESS cost on microgrid annual return

SSD188 and SSD269 have been identified to have a positive annual return at 100% BESS. At 70% BESS, SSD188 shows a $15000 increase in annual return and SSD269 shows a $36796 increase in annual return.

SSD164 and SSD174 show a positive return at 30% BESS and 60% BESS. Based on the 70% reduction threshold, none of these zones are feasible microgrid replacement candidates. All other zones showed no positive return across all BESS reductions.

Figure 33 shows the IPS reduction of BESS on covered service points across discrete permutations.

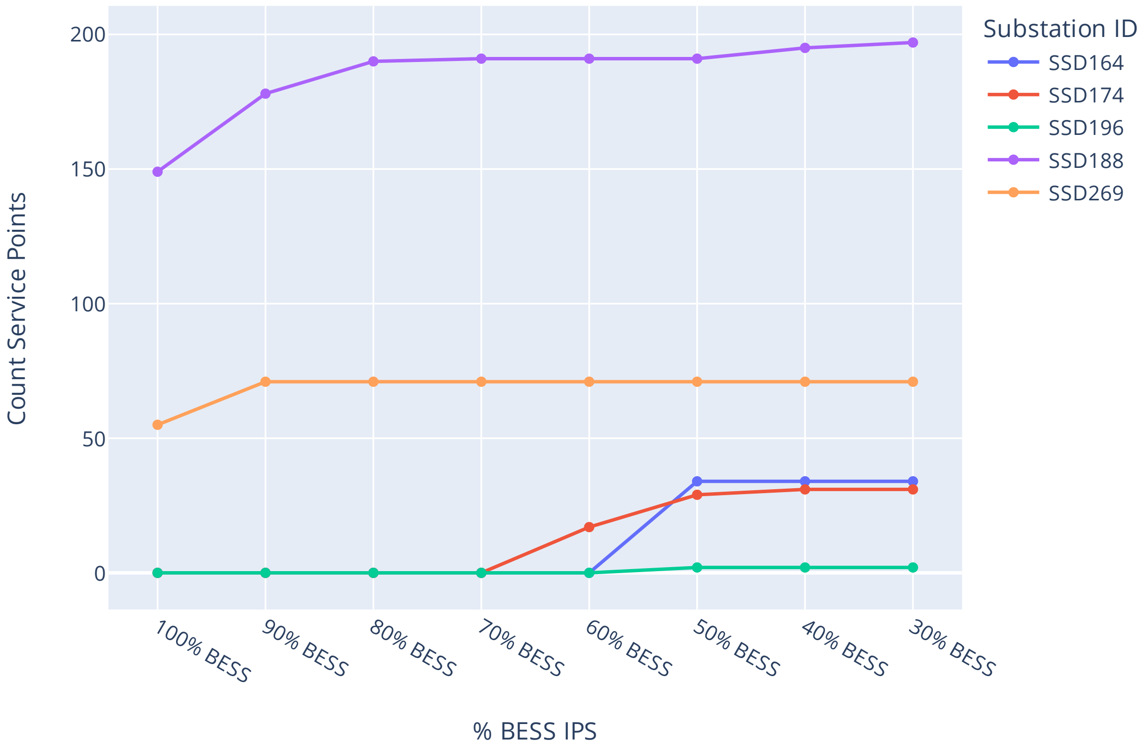


Figure 53: Effect of BESS cost on feasible service points for IPS implementation

At 70% of the initial BESS cost, SSD188 shows an increase of 9 feasible service points, with SSD269 showing an increase of 16 at 90% BESS cost. For SSD269 thresholds below 90% does not produce additional feasible permutations.

SSD164, SSD174 and SSD188 show an increase in covered service points by 34, 29, and 2 at a 50% BESS cost reduction. All other zones showed no increase in feasible service points across all BESS cost reductions.

Figure 33 shows the effect of a BESS cost reduction on microgrid permutations.

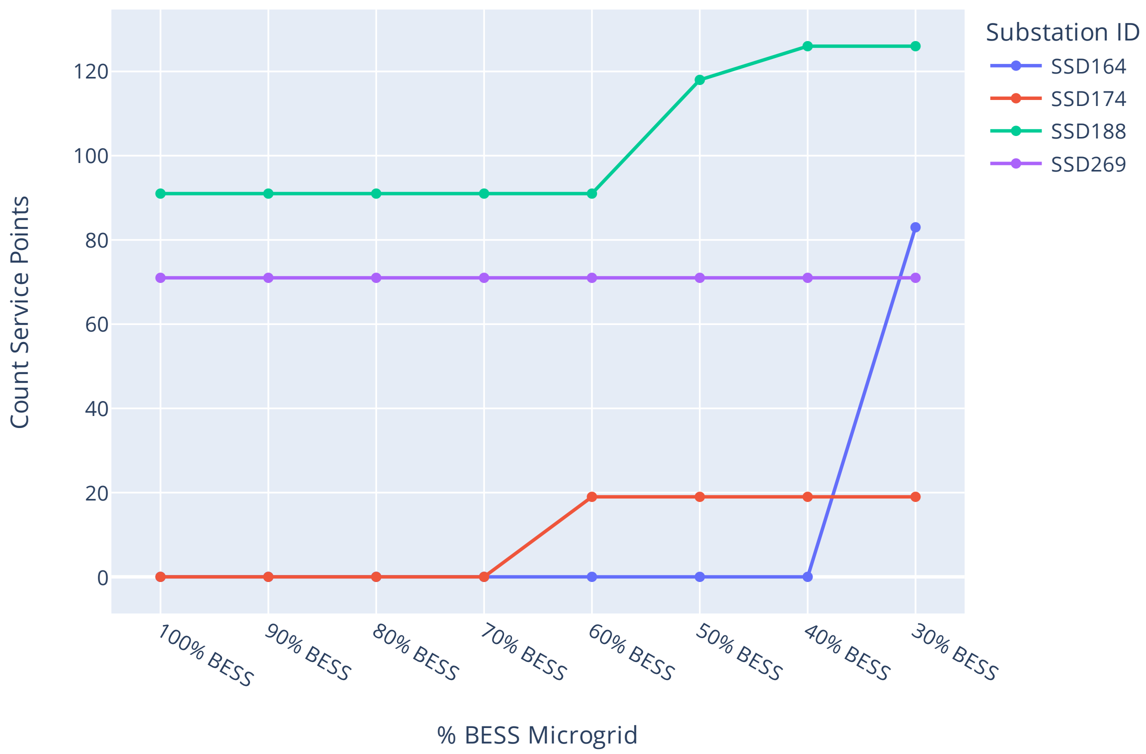


Figure 54: Effect of BESS cost on feasible service points for microgrid implementation

At 70% of the initial BESS price, SSD188 and SSD269 show no increase in feasible service points. For SSD188, an additional 35 service points become feasible for microgrid implementation at 30% BESS cost.

SSD164 and SSD188 show an increase at 30% and 60% BESS cost, resulting in 19 and 83 additional service points being covered. All other zones showed no increase in service points across all BESS reductions.

2.3 Model Verification Study

In the first part of this screening study, it was found that there are several zones which have a positive annual return for both IPS and Microgrids. One area of interest is SSD188 which shows permutations with returns several orders of magnitude greater than other zones. Therefore, conducting a more in-depth investigation of SSD188 will provide insight to the sensitivity of the objective function as well as a sensibility check of the results.

An easy way to extract information for a permutation is to use the screening tool visual library that has been developed for this project. Figure 55 shows the largest IPS permutation in SSD188 obtained from the screening tool.

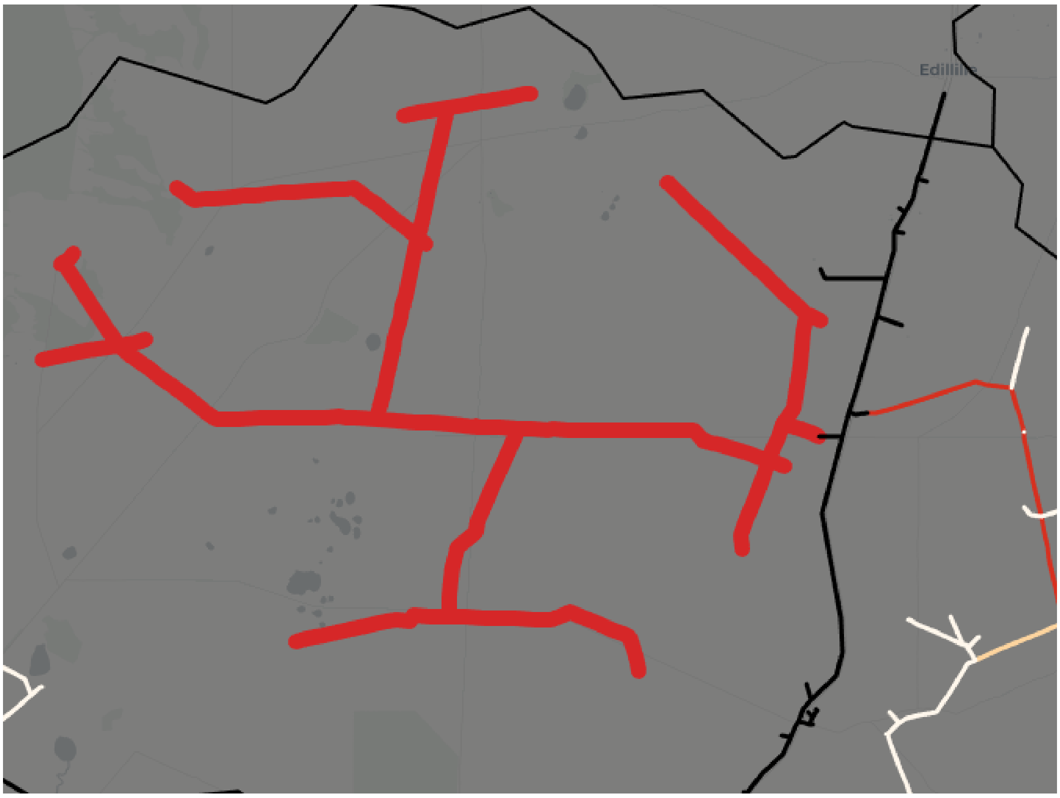


Figure 55: SSD188 Largest Permutation IPS from screening tool

The OH line representation of the permutation of interest is highlighted in red. This permutation is in the centre of the zone close to the rural area of Fountain. The breakdown of the costs associated with the permutation is shown in Table 14.

Table 14: Cost breakdown of SSD188 IPS permutation

Risk Category	Return
VCR	$3960
Bushfire Risk	$72876
Distribution Risk	$484
O/M Risk	$40,119
NPC IPS	$36,816

As expected, the largest contributing cost is VCR, O&M and bushfire risk. By activating the distribution risk layer in the screening tool, it is possible to further investigate the assets and associated costs. The distribution costs are comprised of costs associated with poles and OH conductor lines with risk consequences such as environmental, financial and safety. The distribution risk contributes the least to the total risk of the permutation.

Based on the NPC of the IPS, the load size does not indicate a large commercial or residential asset attached to this portion of the network.

Another area of interest is the largest microgrid permutation situated in SSD188. This permutation neighbours the IPS permutation. Figure 56 shows the largest Microgrid permutation in SSD188 obtained from the screening tool.

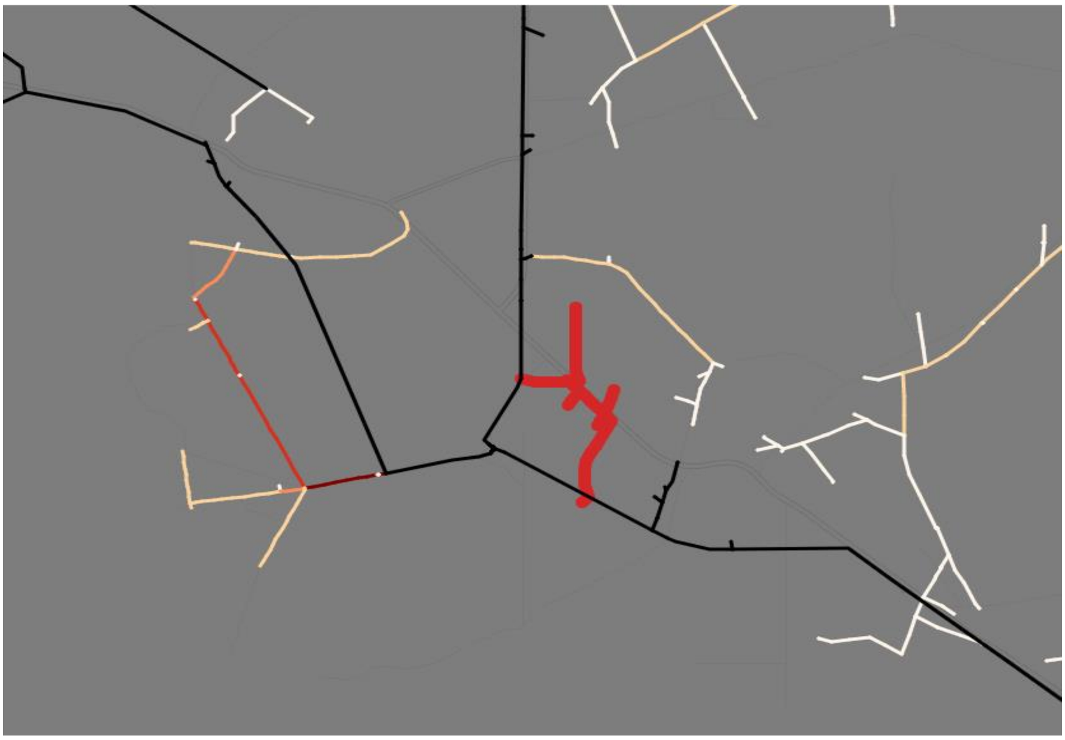


Figure 56: Largest potential microgrid in SSD188 identified by screening

The OH line representation of the permutation of interest is highlighted in red. The breakdown of the costs associated with the permutation is shown in Table 15.

Table 15: Cost breakdown of SSD118 Microgrid permutation

Risk Category	Return
VCR	$1,886
Bushfire Risk	$59,606
Distribution Risk	–
O/M Risk	–
NPC Microgrid	$9,499

The largest contributing factor is the high bushfire risk associated with the feeder covered by the permutation. By comparing the bushfire risk seen in the IPS break seen in Table 14, it can be concluded that this small area near Fountain has a high overall bushfire risk. In conjunction with the small NPC of implementing a Microgrid, the objective function return of this permutation is high.

Overall, SSD188 is a prominent candidate for network modification with both IPS and microgrids due to large bushfire and VCR risks associated with the assets.

3 Conclusion

This screening study found that Individual Power Systems have a higher financial return than microgrids for the same set of network assets. A higher total risk cost due to the inclusion of O&M risk, in combination with VCR and bushfire risk, compensates for the large capital cost associated with implementing IPS systems. The screening tool analysis shows that 2 out of 22 zones studied across the Eyre Peninsula have areas of interest within the SAPN network that are feasible for network decommission and replacement with IPS, covering a total of 204 service points.

The capital costs associated with microgrid implementation greatly outweigh the total risk cost associated with disconnection from SAPN. The screening tool analysis shows that the same 2 out of 22 zones have areas of interest within the SAPN network that are feasible for microgrid implementation, covering a total of 162 service points.

The BESS Cost Sensitivity analysis has shown that in comparison to IPS, the microgrid objective function is less dependent on BESS capex and therefore less susceptible to capex reductions. For both microgrid and IPS implementation, SSD188 and SSD269 are good candidates to re-screen in the future if BESS prices reduce below 70% of current prices. This study showed that there are no additional candidates to consider for future disconnection.

The screening tool sensibility study showed that the largest contributing factors towards a positive return are the large VCR and bushfire risk associated with assets and feeders in combination with a low system cost for a given modification.

The total annual return to SAPN across all discrete network modifications and all zones is $414,456. The total Net Present Value (NPV) over the lifetime of these systems would be approximately $7.3 million, with a discount rate of 2.9%.

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