AusNet

Electricity Distribution Price Review FY2027 to FY2031 (EDPR 2027-31)

Business case: Benalla Number 11 High Voltage Feeder

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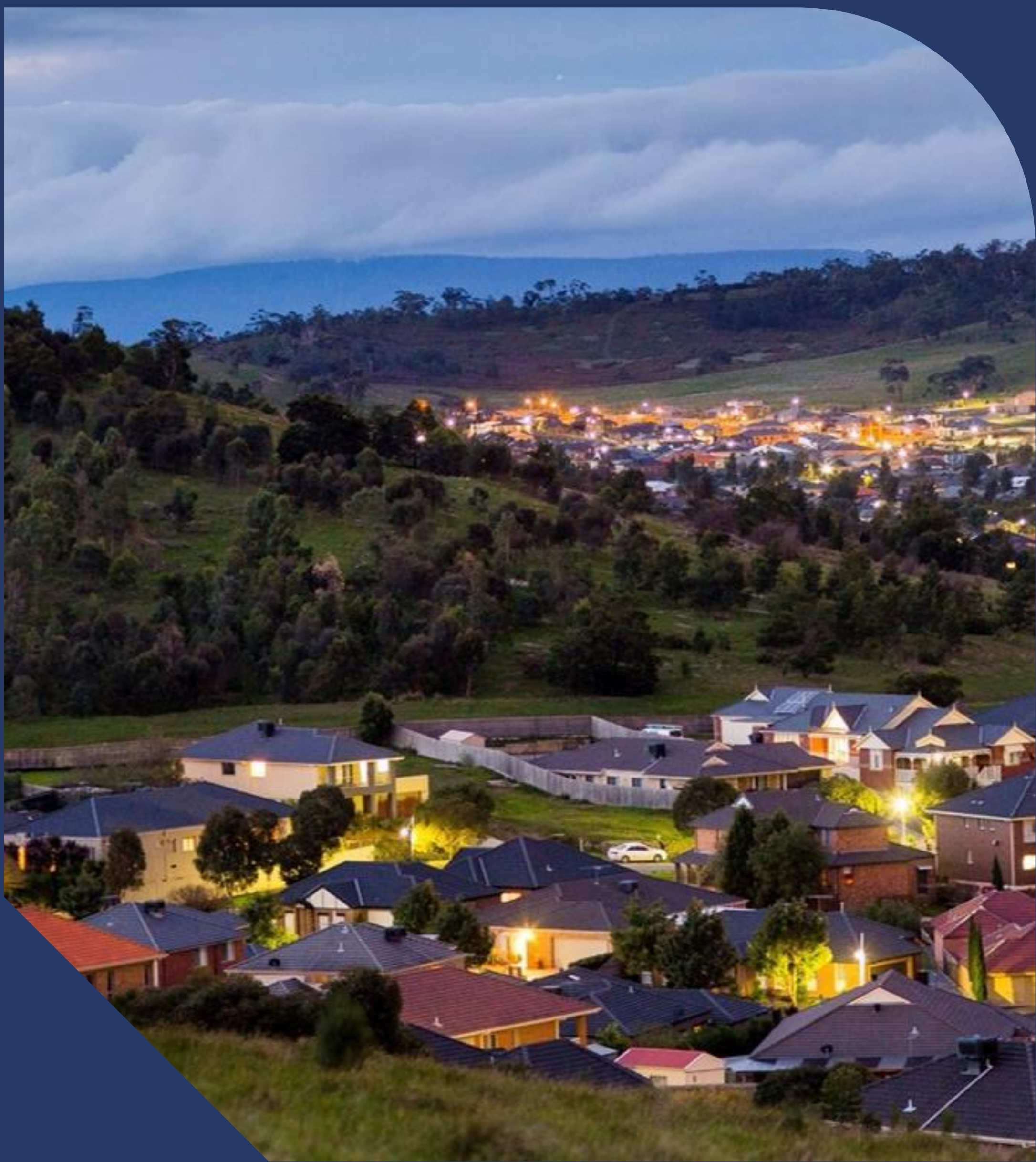

Table of contents

1. Executive summary 2
2. Introduction 4
   - 2.1. Background 4
   - 2.2. Problem definition 4
   - 2.3. Objective of the solution 8
3. Options analysis 9
   - 3.1. Key assumptions 9
   - 3.2. Do nothing calculation methodology 10
   - 3.3. Solution development and assessment methodology 10
   - 3.4. Do nothing 11
   - 3.5. Option 1: New BESS for Euroa 14
   - 3.6. Option 2: Partial supply of BN11 load from RUBA12 and MSD2 16
   - 3.7. Option 3: Euroa diesel generators 19
   - 3.8. Option 4: Proposed Euroa express feeder with a remote REFCL changeover station 21
4. Preferred option and sensitivity testing 24
   - 4.1. NPV comparison 24
   - 4.2. NPV sensitivity 25
5. References 26

1. Executive summary

Introduction

AusNet is proposing to address a summer demand constraint and improve customer reliability on the 22kV Benalla number 11 high voltage feeder, one of the longest feeders in Victoria at 1207 kms in length. The BN11 feeder supplies 4782 customers, and its supply area covers the townships of Violet Town and Euroa as well as the surrounding areas as shown in Figure 1. The BN11 feeder largely falls within a high bushfire risk area and the BN11 feeder is Rapid Earth Fault Current Limiter (REFCL) enabled.

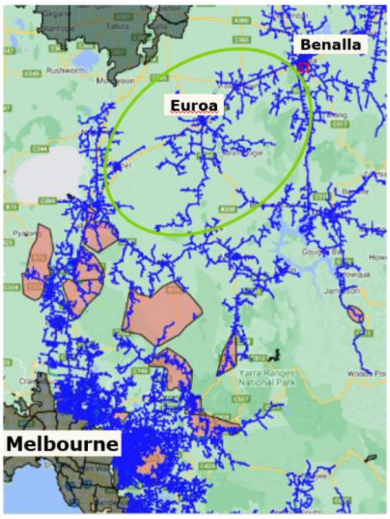

Figure 1: Map showing the BN11 feeder supply area circled in green, the codified electric line clearance areas in pink and low bush fire risk areas in grey. All other areas are classified as high bushfire risk.

Problem

A summer demand constraint exists on BN11 and the risk is currently mitigated via the use of temporary generators located at Euroa. In addition to the demand constraint, BN11 has a reliability problem that can be split into two parts: (1) REFCL loss of protection discrimination is impacting more customers per fault; and (2) The BN11 long radial network topology with no back up supply means that customers are exposed to a higher number of faults and longer duration faults.

Approach

AusNet has an in-flight project to address the BN11 REFCL loss of protection discrimination issue, so the major focus of this business case is on the long radial network topology with no back up supply and demand constraint issues.

A set of credible solution options has been derived and concept level cost estimates built using unit rates. A model was developed to assess each option and to determine the customer value associated with specific outages on the BN11 high voltage feeder using historical outage data, average kW per customer values (calculated from historical data), value of customer reliability (VCR) figures published by the Australian Energy Regulator (AER) and an alternative AusNet residential Quantitative Customer Value (QCV).

Proposed solutions

A detailed assessment was performed for the following credible options:

- New battery energy storage system (BESS) for Euroa.
- Partial supply of BN11 load from AusNet's RUBA12 and MSD2 feeders.
- The installation of diesel generators at Euroa.
- A new Benalla to Euroa express feeder with a remote REFCL changeover station.

To support the options assessment, a net present value (NPV) base case was developed using the value of customer reliability cost estimates, guaranteed service level costs and operating and maintenance cost estimates. A cost estimate and benefits model was developed for each credible option and an NPV assessment including sensitivity testing was undertaken.

Recommendations

Based on the analysis, sensitivity testing and assessment in Table 1, it is recommended that funding be provided for an express feeder to Euroa with a remote REFCL changeover station (as shown in Figure 2) to address the demand constraint and the long radial network topology issue, to improve customer outcomes in the BN11 supply area.

Table 1: BN11 Project Cost-Benefit Summary ($m, 2023-24 dollars[1])

	FY27 to FY31 (undiscounted)			Full assessment period (discounted)			Comments
	Capex	Opex	Total cost	Total cost	Total benefits	NPV	
Do nothing	0.0	3.5	3.5	13.2	-14.4	-27.6	
Option 1 – New BESS	15.6	1.6	17.2	10.9*	9.6*	-1.4	
Option 2 – Partial supply from RUBA12 & MSD2	22.9	1.2	24.0	11.4*	6.4*	-5.0	
Option 3 – Diesel generators	14.6	1.4	16.1	8.6*	9.6*	1.0	
Option 4 – Benalla to Euroa express feeder	23.5	1.0	24.5	11.2*	13.2*	1.9	This is the preferred option as it maximises the NPV, and it is a technically prudent solution.

*Source: AusNet analysis, Note: * relative to do nothing case.*

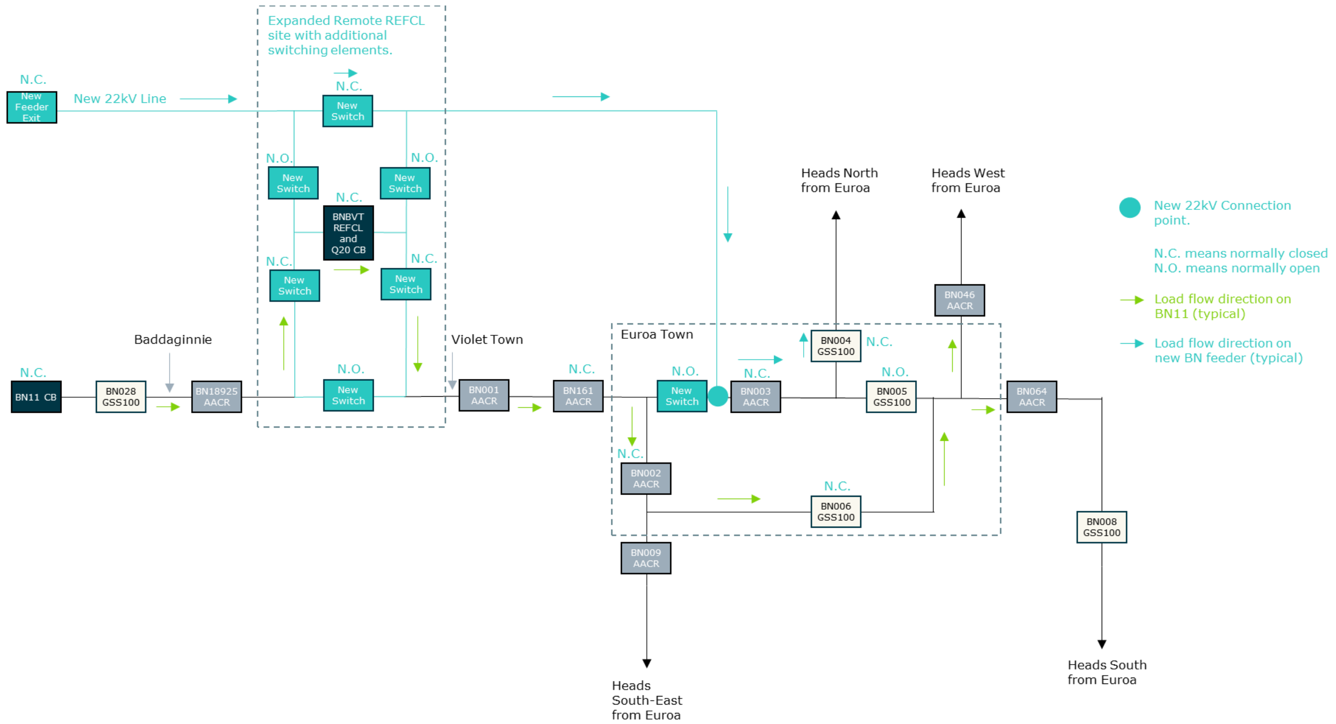

Figure 2: Proposed Benalla to Euroa express feeder with a remote REFCL changeover station. Normal supply arrangement shown.

[1] 2023-24 dollars means 30 June 2024.

2. Introduction

2.1. Background

AusNet is proposing to address a summer demand constraint and improve significant customer reliability issues on the 22kV Benalla number 11 high voltage feeder, one of the longest feeders in Victoria at 1207 kms in length. The BN11 feeder supplies 4782 customers and its supply area covers the townships of Violet Town and Euroa as well as the surrounding areas as shown in Figure 1. The BN11 feeder is largely in a high bushfire risk area and the BN11 feeder is Rapid Earth Fault Current Limiter (REFCL) enabled. Reliability improvement solutions need to ensure that the REFCL network remains compliant. The area supplied by BN11 has been subject to large customer outages due to the radial nature of the feeder since the remote REFCL was commissioned in late 2023 due to the inherent fault identification challenges with the REFCL technology. This in turn has led to increased customer impacts and reliability concerns.

2.2. Problem definition

A summer demand constraint exists on BN11 and the risk is currently mitigated via the use of temporary generators located at Euroa. The demand constraint problem is described in section 2.2.1. In addition to the demand constraint, BN11 has a reliability problem.

To fully understand the BN11 feeder reliability problem and customer outage impacts within the different sections of BN11, a review was carried out of five years of AusNet's reliability data for the different sections of the BN11 feeder before the REFCL was installed, and the reliability data for the BN11 sections from the time that the Remote REFCL was installed to May 2024.

Reviewing this reliability information, it was confirmed that the BN11 reliability problem can be split into two parts:

(1) Remote REFCL loss of protection discrimination is impacting more customers per fault.

(2) Long radial network topology with no back up supply means that customers are exposed to a higher number of faults and longer duration faults.

The two parts to the reliability problem are described in sections 2.2.2 and 2.2.3 below.

2.2.1. Existing demand constraint on BN11

The existing summer demand constraint on BN11 is currently mitigated via the use of 2.6MW of temporary generators located at Euroa. This includes 2 x 0.8MW and 2 x 0.5MW generator units that run approximately ten times per annum, on hot days. This is a real active intervention and it has been sized based on actual peak demand and network characteristics.

2.2.2. Remote REFCL loss of protection discrimination is impacting more customers per fault

Background

To meet Required Capacity, as defined in the Electricity Safety (Bushfire Mitigation) Regulations, AusNet installed a remote REFCL on the BN11 high voltage feeder and activated it on 8 November 2023. The BNBVT Remote REFCL site location is shown in Figure 3 and an aerial photo of the remote REFCL site is shown in Figure 4.

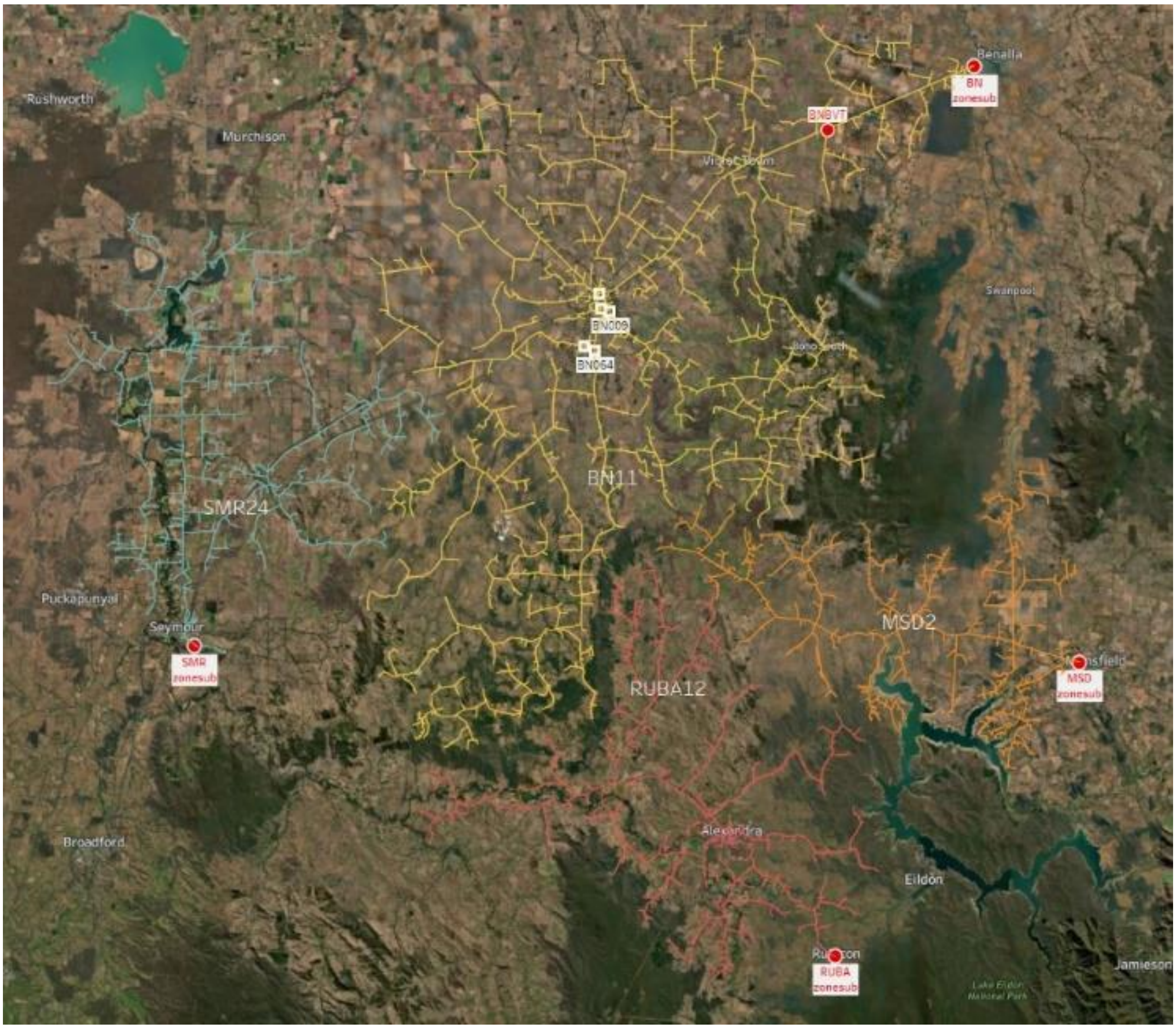

Figure 3: BNBVT Remote REFCL site on BN11. The BNBVT site is shown as a red dot to the left of BN zone substation. The BN11 feeder is shown in yellow.

Figure 4: Aerial photo of the BNBVT Remote REFCL site.

Problem

With the REFCL in operation, the network downstream of BNBVT in Figure 3 operates as a resonant network for phase to ground faults on the poly phase network. This means that traditional protection devices such as conventional ACRs and fuses will not detect and respond to earth faults on the network. Fuses, ACRs and feeder circuit breakers are usually set up, from a protection and reliability viewpoint, so that they have discrimination between devices. Typically a sustained earth fault downstream of a fuse will be detected and cleared by the fuse, minimising the number of customers impacted, rather than the upstream ACRs or feeder circuit breaker.

Instead, the BNBVT operates for earth faults in sections that are traditionally picked up by fused sections and ACR covered sections of the feeder. This means that more customers are impacted for each earth fault on the system, as the BNBVT now sees and responds to all earth faults downstream. In summary, protection discrimination is lost for earth faults downstream of the BNBVT when it is in operation.

The BNBVT does not include a neutral bypass bus, meaning that the REFCL cannot be switched to traditional protection when it is in operation.

In addition to the increase in the number of customers impacted per fault (as shown in FY24 in Figure 5), the duration of faults in the fire season is longer due to the requirement to patrol the feeder before the feeder is reenergized following a REFCL operation. Given the length of the poly phase network downstream of the BNBVT is 615 km, this can result in long customer restoration times.

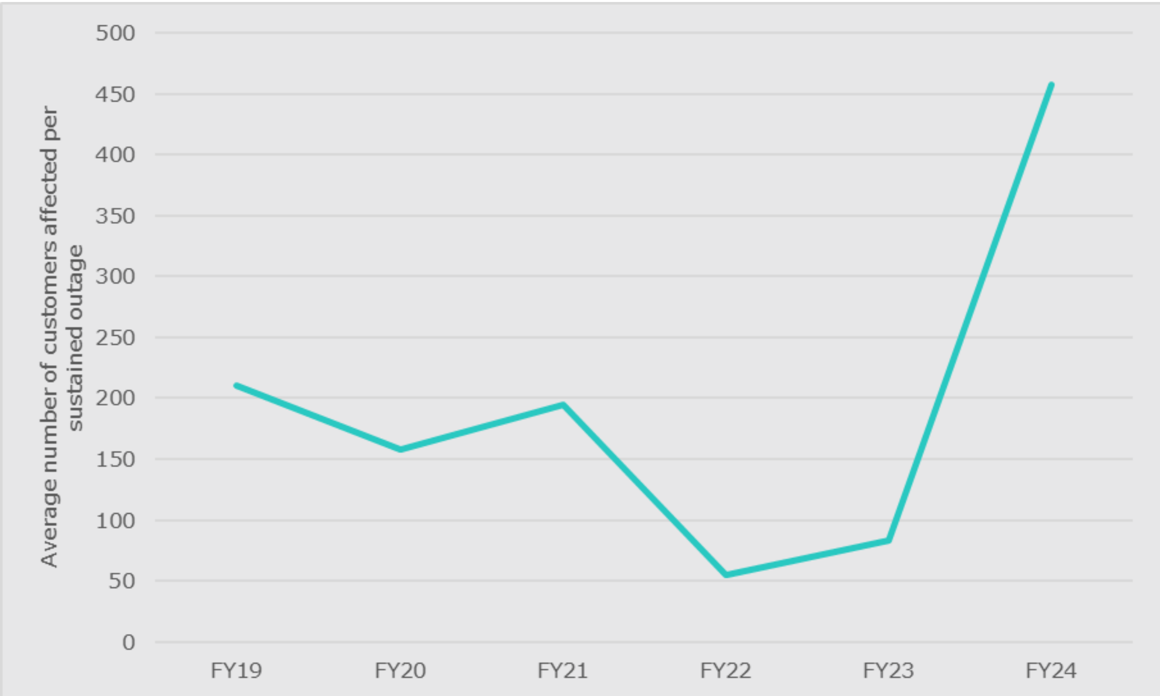

Figure 5: BN11 average number of customers affected per sustained outage per annum, FY19 to FY24 (up to 25 May).

2.2.3. Long radial network topology with no back up supply

Background

The BN11 high voltage feeder supplies the townships of Violet Town and Euroa to the south west of Benalla zone substation as well as the extended supply areas seen in Figure 6 as spurs along the main feeder route between Benalla and Euroa and the sections that exit Euroa to the north, west, south and southeast.

The line length of the BN11 feeder is 1207 kms which includes 167 kms of three phase line, 493 kms of single phase line and 547 kms of SWER line.

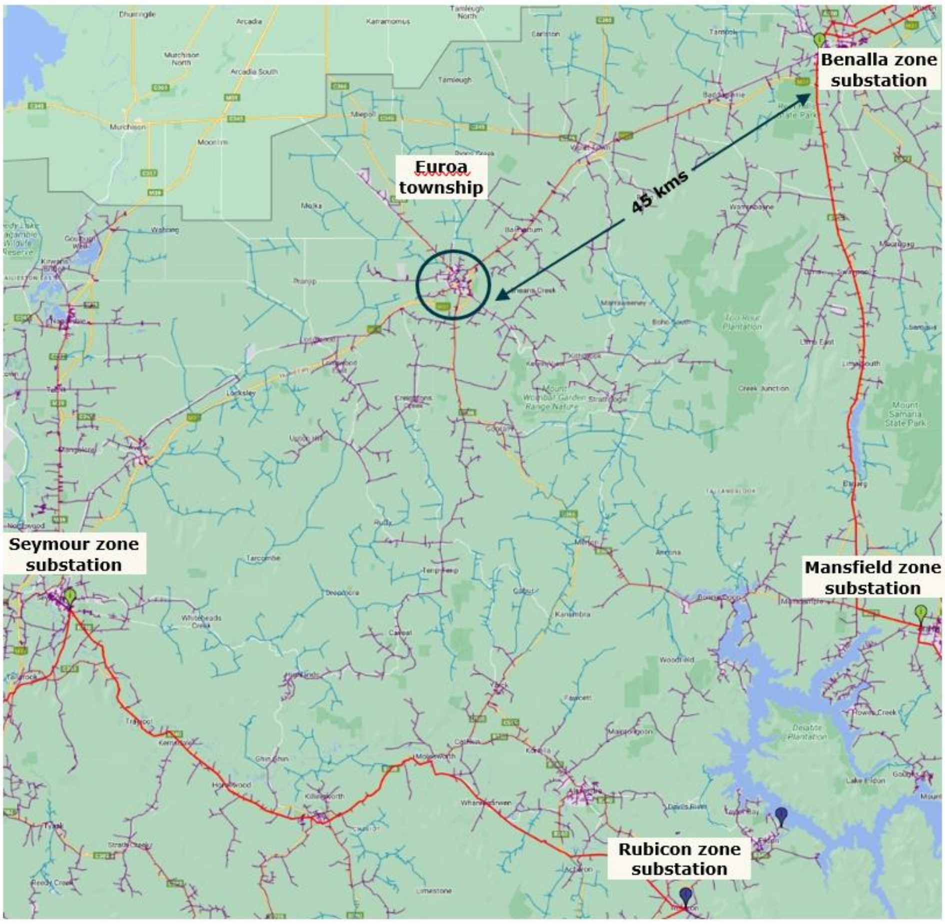

Figure 6: Map of the BN11 supply area and surrounding electricity network. Refer to the 22kV network in purple, 66kV network in red and SWER network in light blue.

Figure 7: Victorian transmission lines and terminal stations.

Problem

From a distribution network perspective, BN11 is known as a long rural radial feeder. As seen in Figure 6, the main township of Euroa is a long distance from surrounding zone substations, Benalla, Mansfield, Seymour and Rubicon. Euroa is also distanced from 66kV sub-transmission lines and transmission lines (as shown in Figure 7), meaning that the establishment of a zone substation or terminal station at (or near) Euroa would cost a lot more than the station itself as it would require extensive line investment.

The radial topology of BN11 means that it does not have back up supply links to other feeders. For example, if there is a fault between Benalla zone substation and Euroa, all of Euroa loses supply along with all customers downstream of Euroa as there is no present way to back feed these customers from other points of supply.

The long length of the supply line from BN zone substation to Euroa also means that this feeder is more exposed to fault causes such as weather events, including storms and lightning, and wildlife compared to shorter line lengths.

2.2.4. Key assumptions of the problem

The following are the key assumptions of the problem:

- Qualitative and quantitative customer value of reliability remains relatively stable over the near to medium term.
- The in-flight project will address the REFCL discrimination issue.

2.3. Objective of the solution

The objective of the solution is to obtain a prudent and efficient long term option to:

- reduce the risk associated with the demand constraint on BN11,
- improve the electricity service to heavily outage impacted and remote customers on the BN11feeder in the AusNet electricity supply area. The solution will focus on the long radial network topology with no back up supply issue. It has been assumed that the in-flight project will address the REFCL discrimination issue.

3. Options analysis

Given the network characteristics described in section 2, the following credible options were considered (in addition to the do nothing option):

- Option 1: New BESS for Euroa.
- Option 2: Partial supply of BN11 load from RUBA12 and MSD2
- Option 3: Euroa diesel generators.
- Option 4: Proposed Benalla to Euroa express feeder with a remote REFCL changeover station.

These options address the demand constraint and the "long radial network topology with no back up supply" problem.

3.1. Key assumptions

A net present value assessment was used to determine the best solution for the customers on BN11 and the key assumptions are detailed in Table 2. It has been assumed that the BN11 Remote REFCL loss of protection discrimination issue will be resolved by an in-flight project as described in the assumptions below.

Table 2: Key assumptions

	Value	Comments
WACC	5.56%	
Higher WACC	7.00%	The higher WACC value is used in the sensitivity scenarios.
Evaluation period	30 years	
Value of Customer Reliability (VCR)	Refer to comment.	AER VCR Figures in 2023-24 dollars were used. VCR values have been applied to BN11 in accordance with the defined VCR customer categories.

Source: AusNet analysis

Additional assumptions are listed below:

- Five years of actual customer outage data used. Pre-BNBVT Remote REFCL outage data was used to calculate the benefits as it has been assumed that the post REFCL outages will be reduced by AusNet's in-flight project to address the BN11 Remote REFCL loss of protection discrimination issue.
- An average annual customer minutes of supply has been determined.
- The lost energy has been calculated based on an average kW per customer based on historical actuals.
- Solar energy has been incorporated into the average kW per customer value based on the number of solar installations on each feeder. A description of the methodology is provided in section 3.2.1.1.
- Average historical Guaranteed Service Level (GSLs) payment data has been used to forecast GSLs.
- The economic cost of unserved energy is based on the AER's VCR values and the application of the Value of Network Resilience (VNR) as per the AER's Value of Network Resilience 2024[2].
- Operational costs associated with faults determined using historical actuals.

[2] AER's Value of Network Resilience 2024, Final Decision, September 2024.

3.2. Do nothing calculation methodology

3.2.1. Customer outage impacts

The economic impacts per annum under a do nothing scenario have been calculated using the historical actual outage data which provides the number of customers impacted per outage and the outage durations. Using these inputs, the value of customer outage impacts in different sections of BN11 was calculated using the VCR applicable to the BN11 feeder, the application of the VNR, and the average kW per customer (for BN11). Sections 3.4.1 and 3.4.2 further describe the approach taken to calculate the customer outage impacts in different sections of BN11.

3.2.1.1. Average kW per customer and solar energy

The average kW per customer was calculated using the sum of the annual historical meter data plus solar energy, divided by the number of customers on BN11.

Solar energy was added to the historical customer meter data based on the following calculation and assumptions:

- Number of solar customers on feeder x 6570kWh per annum per household with solar.
- 6570kWh per annum is based on the Department of Climate Change, Energy, the Environment and Water typical average daily generation of 3.6 kWh[3] per kW of solar panels multiplied by 365 days multiplied by an assumed average system size of 5kW.

3.2.1.2. Guaranteed service level (GSL) costs

The historical guaranteed service level (GSL) costs on BN11 were also reviewed. Using this historical data, the average GSL impact per annum was calculated and used as an annual forecast cost in the do nothing scenario.

3.2.2. Existing demand constraint on BN11

The existing demand constraint mitigation is explained in section 2.2.1 and the costs of the temporary generation invention has been used instead of an energy at risk calculation as it is a real cost and the generation has been sized based on actual peak demand and network characteristics. It has been assumed that the BN11 demand constraint (and associated generation requirement) increases over time, in line with the BN11 demand forecasts.

3.3. Solution development and assessment methodology

Following the problem identification, AusNet undertook an exploration phase that included our team engaging a distribution network service provider (DNSP) representative in another state to understand its approach to customer reliability on long feeders; and undertaking an internal solutions ideation workshop with electricity network specialists.

Taking the outputs of the exploration phases, a set of credible solution options was derived and concept level cost estimates built using unit rates. To assess each option, a quantitative approach was undertaken which included:

- Identification of the problems on the BN11 feeder using five years of historical outage information.
- Credible solution identification and development using network information, engineering input and historical unit costs.

[3] https://www.energy.gov.au/solar/get-know-solar-technology/solar-panels. Typical average daily generation figures are listed and the Melbourne region was selected as the most appropriate figure for this application.

- An economic valuation of the customer benefits based on the energy lost during network outages and the AER's value of customer reliability for the base case (do nothing) and each proposed intervention.
- A net present value assessment (**NPV**) for each proposed intervention against the base case (do nothing).
- Selection of a preferred option based on the NPV analysis, customer considerations and a sensitivity analysis using variable discount rates and costs.

The preferred solution was also assessed using the alternative residential QCV.

3.4. Do nothing

3.4.1. Customer outage impacts in different sections of BN11 (Do nothing case)

To better understand the customer impact, historical outage information was reviewed for key switching devices on BN11. These include the BN11 circuit breaker, BN001 which is located near Violet Town, BN161 which is located at the "electrical entrance" to Euroa, and the four exits from Euroa township, BN004, BN009, BN046 and BN064. The devices are shown in a left to right feeder representation in Figure 8.

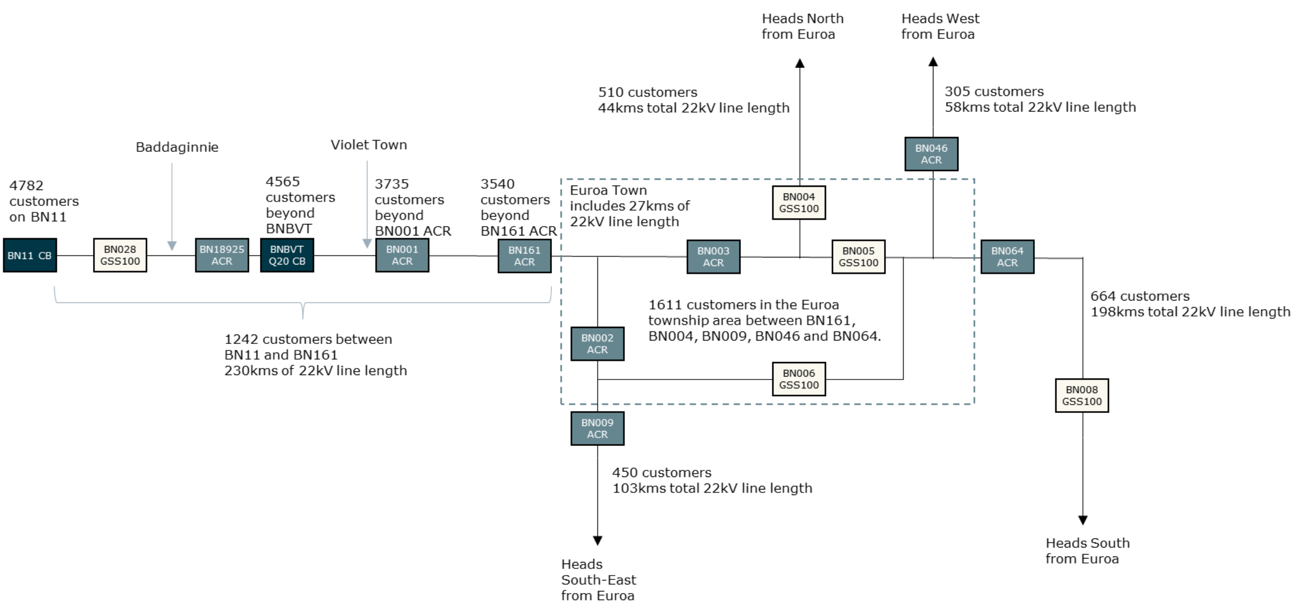

Figure 8: Representation of the existing BN11 feeder showing key switching elements.

Using five years of historical outage data, the average cost per annum was calculated for the key devices using the average:

- sustained outage time, in hours, which was derived from the historical outage data set,
- number of sustained outages per annum, which was derived from the historical outage data set,
- kW per customer, derived from the historical energy use on BN11 in 2023 including the contribution of solar,
- customer minutes off supply (CMOS), derived from the number of customers impacted, the sustained outage time and the number of sustained outages per annum,
- unserved energy (kWh), derived from the kW per customer and CMOS per annum,
- cost per annum, derived from the unserved energy, the weighted VCR and application of the Value of Network Resilience (VNR) approach.

The calculated results for each key device are shown in Table 3.

Table 3: Average annual cost associated with key devices on BN11, ($m, 2023-24 dollars).

Switch ID	Customers	Average sustained outage time, Hrs	Average number of sustained outages per annum	Average kW per customer	Average CMOS per annum	Average cost per annum
Feeder CB	4,782	3.15	1.49	0.946	1,349,285	$1,073,970
BN18925 / BNBVT	4,564			0.946		
BN001	3,735	0.56	0.19	0.946	23,595	$18,780
BN161	3,540	2.29	0.56	0.946	272,605	$216,982
BN004	510	4.15	0.19	0.946	23,723	$18,883
BN046	305	2.86	0.37	0.946	19,584	$15,588
BN064	664	3.29	0.56	0.946	73,561	$58,551
BN009	450	2.97	0.37	0.946	29,967	$23,852

Using this data, the impact to customers was calculated for the BN11 circuit breaker to the BN161 ACR which is located at the start of the Euroa township. This is shown in Table 4.

Table 4: Average annual cost associated the BN11 CB to BN161 ACR, ($m, 2023-24 dollars).

Section	Customers	Average sustained outage time, Hrs	Average number of sustained outages per annum	Average kW per customer	Average CMOS per annum	Average cost per annum
BN11 CB to BN161 ACR[4]	1242	3.15	1.49	0.946	350,442	$278,936

From the calculations in Table 3 and Table 4, it can be seen that the impact of feeder circuit breaker outages for customers in Euroa township and downstream of the township is $1,073,970 minus $278,936 equates to $795,035 per annum. In summary, the radial network topology is having a big impact on customers in Euroa and downstream of Euroa.

Following the analysis in this section, it has been assumed that the benefits of:

- providing an extra supply point (or source of supply) to Euroa equates to $795,035 per annum,
- augmenting or developing asset management solutions for the sections exiting Euroa township equates to $18,883 for BN004, $23,852 for BN009, $15,588 for BN046 and $58,551 for BN064.

3.4.2. Alternative residential VCR method

AusNet has performed its own willingness to pay surveys and analysis to arrive at a higher residential VCR of $54.80 per kWh which is higher than the AER version of $26.18 (in FY2024 $s[5]). This is referred to as the Quantitative Customer Value (QCV)

Swapping the AER residential VCR with AusNet's QCV results in alternative annual costs as shown in Table 5.

[4] The impact of BN001 outages was deemed negligible for this section.
[5] FY2024 means 30 June 2024.

Table 5: Average annual cost associated with key devices on BN11, ($m, 2023-24 dollars) using AusNet's residential QCV.

Switch ID	Customers	Average sustained outage time, Hrs	Average number of sustained outages per annum	Average kW per customer	Average CMOS per annum	Average cost per annum
Feeder CB	4,782	3.15	1.49	0.946	1,349,285	$1,265,058
BN18925 / BNBVT	4,564			0.946		
BN001	3,735	0.56	0.19	0.946	23,595	$22,122
BN161	3,540	2.29	0.56	0.946	272,605	$255,588
BN004	510	4.15	0.19	0.946	23,723	$22,243
BN046	305	2.86	0.37	0.946	19,584	$18,361
BN064	664	3.29	0.56	0.946	73,561	$68,969
BN009	450	2.97	0.37	0.946	29,967	$28,096

Following the analysis approach in this section, it has been assumed that the benefits of:

- providing an extra supply point (or source of supply) to Euroa equates to $936,492 per annum with AusNet's alternative residential QCV.

3.4.3. Demand constraint on BN11 (Do nothing case)

Refer to the description in section 3.2.2.

Considering that there is an active demand constraint on BN11, which is forecast to increase in size, summer generation has been included to support the base case. This approach is considered reasonable as AusNet already deploys generators in Euroa to manage peak demand on this high voltage feeder. The assumptions associated with the generator support in the base case are as follows:

- $474K for 2.6MVA of summer generation support between 2024 to 2030
- $618K for 3.6MVA of summer generation support between 2031 to 2036
- $762K for 4.6MVA of summer generation support from 2036 onwards.

The 2024 to 2030 MVA size is based on AusNet's existing summer generation support sizing. The forecast MVA size and timing is derived from AusNet's BN11 demand forecast, using the existing 2.6MVA size as a base.

3.4.4. Do nothing case NPV inputs

Given the customer complaints on BN11, it has been assumed that AusNet will need to treat BN11 with additional focus if there is no commitment to capital investment.

Therefore, in the NPV base case the following has been assumed:

- Value of expected unserved energy impacts as per the values in sections 3.4.1 and 3.4.2. This covers the impact of not having an additional supply point in Euroa.
- Generation support expenditure as per the values in section 3.4.3.
- $114K per annum assumed for GSLs without additional supply point to Euroa.
- $10K per annum allowance for back office responses to customer complaints.
- $50K per annum for additional line inspections and proactive defect rectification on the line between Benalla and Euroa.
- $50K per annum to preemptively place field resource in Euroa prior to storm events.

It is not expected that additional line inspections and preemptive storm resourcing activities will materially influence the annual customer outage impact. However, these activities will show the community that AusNet is taking on additional proactive activity and it may prevent the outages getting worse.

It is also assumed that the dollar value of these activities will reduce in each of the credible solution options.

The do nothing cost and benefits are shown in Table 6 (using the AER VCR values) and Table 7 (using the AusNet Residential QCV).

Table 6: BN11 Do nothing scenario ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	0.70	0.66	0.63	0.59	0.56	3.14	13.25
Benefits	-0.81	-0.78	-0.75	-0.72	-0.69	-3.75	-14.36
						NPV	**-27.61**

Source: AusNet analysis

Table 7: BN11 Do nothing scenario (using AusNet Residential QCV) ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	0.70	0.66	0.63	0.59	0.56	3.14	13.25
Benefits	-0.96	-0.92	-0.88	-0.85	-0.81	-4.41	-17.05
						NPV	**-30.30**

Source: AusNet analysis

3.5. Option 1: New BESS for Euroa

This section investigates the new BESS at Euroa in further detail.

BESS sizing and major equipment:

Average demand downstream of BN161 is ~3MVA and peak demand is ~8MVA. The average sustained outage times are 3-4hrs.

Based on this demand and outage information, it is recommended that the following equipment be installed:

- BESS 2 x 5MVA inverters and 2 x 7.5MWh battery installations (15MWh in total).
- 10MVA three winding step up transformer 415V/415V/22kV.
- 1 x ACR.

3.5.1. Cost

3.5.1.1. Capex

The capital cost estimate is shown in Table 8 and the yearly capex is shown in Table 9. The capital cost estimate assumptions are listed below.

Assumptions:

- $596K per MWh for BESS storage. This covers the total cost including balance of plant. This is an average of the 2hrs and 4hr $2024s storage cost figures from the CSIRO Gencost report.
- Transformer and ACR costs based on AusNet's unit rates.
- $500K for additional site work
- $200K allowance for minor plant and equipment.
- Land costs assumed as $300K including transaction costs.
- Design costs estimated at 4% of construction costs (including materials).
- Subcontractor indirect costs of 10%.
- Project management and construction management costs applied at 8% of design and construction costs.
- Risk of 10% added to direct costs.

Table 8: Option 1 New BESS for Euroa, capital cost estimate.

	Item	$m, FY2024
Capex	BESS 2 x 5MVA inverters and 2 x 7.5MWh battery installations (15MWh in total)	8.9
	10MVA three winding step up transformer 415V/415V/22kV	1.5
	Additional allowance for site work	0.5
	ACR	0.1
	Allowance for minor plant and equipment	0.2
	Land	0.3
	Sub-total – construction	11.5
	Design	0.5
	Sub-total – design and construction	12.0
	Subcontractor indirect costs	1.2
	Project management and construction management	1.0
	Total cost excluding risk	14.2
	Risk	1.4
	Total	**15.6**

Replacement cost timing

It has been assumed that the BESS units will need to be replaced in 20 years. Degradation of the batteries in years 1 to 20 years has been excluded from the analysis.

Table 9: Option 1 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	9.35	5.90	-	-	-	15.25	20.25

Source: AusNet analysis

3.5.1.2. Opex

The Opex cost relative to the do nothing case is shown in Table 10. This value includes O&M costs associated with the BESSs of $200K per annum.

Table 10: Option 1 Opex, relative to do nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Opex	0.70	0.20	0.21	0.19	0.18	1.48	3.94

Source: AusNet analysis

3.5.2. Benefits

75% of the baseline benefits have been assumed based on the BESS being able to operate as a backup when the REFCL is in bypass mode. This assumption can be refined with further investigation, although going to 100% does not have a material impact on the outcome. The benefits are shown in Table 11.

Table 11: Option 1 Benefits, relative to do nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Benefits	-	-	0.37	0.36	0.35	1.08	6.38

Source: AusNet analysis

3.5.3. Summary

The benefits of the BESS option are limited as the BESS cannot be used in island mode in the times when REFCL protection is required on the 22kV polyphase network. This is due to the BESS microgrid section not being REFCL protected when it is in island mode (i.e. when a feeder outage occurs).

Other considerations:

- The BESS storage capacity is generally limited. It may not be viable for long duration outages. A diesel generator may be required to support long duration outages.
- Some of the cost may be offset by a third party lease agreement for use of the BESS capacity in the market.

The cost and benefit summary (relative to the base case) is shown in Table 12.

Table 12: Option 1 Summary, relative to do nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	9.35	5.44	-0.42	-0.40	-0.38	13.59	10.94
Benefits	-	-	0.56	0.54	0.52	1.62	9.58
						NPV	**-1.37**

Source: AusNet analysis

3.6. Option 2: Partial supply of BN11 load from RUBA12 and MSD2

This section investigates the Partial supply of BN11 load from the RUBA12 and MSD2 feeders in further detail.

REFCL constraint review

Prior to exploring the costs associated with this option, it is important to understand the technical REFCL constraints to factor in any limitations to the benefits.

To assess the REFCL impact, the REFCL capacitance current results were reviewed for BN, MSD and RUBA REFCLs.

The capacitance figures are as follows:

- 71 Amps downstream of the BN11 Remote REFCL
- 71 Amps on MSD Bus 1 which supplies MSD2
- 70 Amps on RUBA Bus 1 which supplies RUBA12
- 21 Amps on MSD2
- 29 Amps on RUBA12

Based on technical advice from AusNet's REFCL specialists:

- If the section downstream of the BN11 remote REFCL is transferred to MSD2 or RUBA12, it will take the MSD and RUBA buses very close to REFCL limits.
- Similarly, if the section downstream of the BN11 remote REFCL is transferred to MSD2 or RUBA12 the feeders will exceed the 80A feeder limit.

This means that a MSD2 or RUBA12 extension will only be able to pick up part of the sections downstream of the BN11 remote REFCL. These feeder tie sections will also get smaller in future as capacitance grows on BN11 and MSD2 or RUBA12.

For the purpose of this assessment, it has been assumed that two ties will be created from BN11 to MSD2 and RUBA12 to split the capacitance impact on the feeders and the buses.

The ties may require underground cable as they pass through areas with vegetation. The underground cable will also impact the capacitance of the network and the additional overhead ties will have some impact on the REFCL.

3.6.1. Cost

3.6.1.1. Capex

Two feeder ties have been assumed with the assumptions noted below.

Assumptions:

- 18kms between Merton and Strathbogie for the MSD2 to BN009 tie.
- 21kms between Yarck and Terip Terip for the RUBA12 to BN064 tie.
- Allow 4km allowance for deviations to direct road based line route.
- Total 43kms: Assume 39 kms of overhead and 4kms of underground. The underground length has been assumed as the new route passes through vegetated areas and reserves.
- Line uprates have not been assessed. If required, it is assumed that they will have a similar cost to new builds as the line will need to be built to the most recent Australian standards.
- Switch costs based on AusNet's unit rates.
- $300K allowance for control integration works.
- No costs for easements have been assumed.
- No costs for three phase voltage regulators have been assumed. These may be required following detailed analysis.
- Design costs estimated at 4% of construction costs.
- Subcontractor indirect costs of 10%.
- Project management and construction management costs applied at 8% of design and construction costs.
- Risk of 10% added to direct costs.

The capital cost estimate is shown in Table 13 and the yearly capex is shown in Table 14.

Table 13: Option 2 Partial supply of BN11 load from RUBA12 and MSD2, capital cost estimate.

	Item	$m, FY2024
Capex	39kms of 22kV overhead line	13.7
	4 kms of 22kV underground	2.8
	2 x Gas insulated switches	0.1
	Allowance for control integration	0.3
	Sub-total – construction costs	17.0
	Design	0.7
	Sub-total – design and construction	17.6
	Subcontractor indirect costs	1.8
	Project management and construction management	1.4
	Total cost excluding risk allowance	20.8
	Risk	2.1
	Total	**22.9**

Replacement cost timing

Not included. New assets assumed to have a 50 year life.

Table 14: Option 2 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	13.73	8.67	-	-	-	22.40	22.40

Source: AusNet analysis

3.6.1.2. Opex

The Opex cost relative to the do nothing case is shown in Table 15. This value includes O&M costs associated with the new feeder ties, assumed as $50K per annum for marginal increases in inspection and minor defect rectification.

Table 15: Option 2 Opex, relative to do nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Opex	-	-0.53	-0.53	-0.50	-0.48	-2.04	-10.99

Source: AusNet analysis

3.6.2. Benefits

The following ties have been assumed.

- MSD2 and BN009: Between Merton and Strathbogie, 18kms by road.
- RUBA12 and BN064: Between Yarck and Terip Terip. 21kms by road.

Benefits will be limited by the following:

- The ties only pick up two of the four exits from Euroa, BN009 and BN064, meaning that faults on these two sections between Euroa and the tie points will impact the benefits.
- Ties will be limited from a loading perspective.
- Ties are limited by the REFCL constraints mentioned in this section (above).

Given the benefit considerations above, it has been assumed that the full Euroa township (and downstream of Euroa) benefits can only achieved 50% of the time. This assumption can be refined with further modelling and analysis, although it should also be noted that the benefit of the feeder ties will diminish over time with the growth in the network impacting the REFCL limits and increasing demand impacting the capacity of the feeder ties.

The benefits are shown in Table 16.

Table 16: Option 2 Benefits, relative to do nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Benefits	-	-	0.37	0.36	0.35	1.08	6.38

Source: AusNet analysis

3.6.3. Summary

The benefits of the feeder ties are limited by REFCL and demand constraints. Other considerations:

- A remote REFCL may be required in future to maintain compliance.

A cost and benefit summary (relative to the base case) is shown in Table 17.

Table 17: Option 2 Summary, relative to do nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	13.73	8.14	-0.53	-0.50	-0.48	20.36	11.41
Benefits	-	-	0.37	0.36	0.35	1.08	6.38
						NPV	-5.03

Source: AusNet analysis

3.7. Option 3: Euroa diesel generators

This section investigates the new diesel generators at Euroa in further detail.

Diesel Generator sizing and major equipment

Average demand downstream of BN161 is ~3MVA and peak demand is ~8MVA. The average sustained outage times are 3-4hrs.

Based on this demand and outage information, it is recommended that the following equipment be installed:

- 4 x 2.25MVA (4 x 2MW) diesel generators.
- 2 x 5MVA three winding step up transformers 6.6kV/6.6kV/22kV.
- 2 x ACRs.

3.7.1. Cost

3.7.1.1. Capex

The diesel generator capex estimate option has the following assumptions:

- $980K per MW for Diesel generators. This covers the equipment cost.
- $300K installation cost.
- ACR costs based on AusNet's unit rates. Transformer size does not match standard size in the AusNet unit rate list, so an assumption is made in the table below.
- $500K for site work.
- $200K allowance for minor plant and equipment.
- Land costs assumed as $300K including transaction costs.
- Design costs estimated at 4% of construction costs.
- Subcontractor indirect costs of 10%.
- Project management and construction management costs applied at 8% of design and construction costs.
- Risk of 10% added to direct costs.

The capital cost estimate is shown in Table 18 and the yearly capex is shown in Table 19.

Table 18: Option 3 Euroa diesel generators, capital cost estimate.

	Item	$m, FY2024
Capex	Diesel generators 8MW	7.8
	2 x 5MVA three winding step up transformers 6.6kV/6.6kV/22kV	1.5
	Installation cost	0.3
	Additional allowance for site work	0.5
	2 x ACRs	0.2
	Allowance for minor plant and equipment	0.2
	Land	0.3
	Sub-total - construction costs	10.8
	Design	0.4
	Subcontractor indirect costs	1.1
	Project management and construction management	0.9
	Total cost excluding risk allowance	13.3
	Risk	1.3
	Total	**14.6**

Replacement cost timing

Diesel generators can last 20-30 years if they are appropriately maintained. Replacement at 25 years has been assumed.

Table 19: Option 3 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	8.78	5.55	-	-	-	14.33	17.91

Source: AusNet analysis

3.7.1.2. Opex

The Opex cost relative to the do nothing case is shown in Table 20. This value includes O&M costs associated with the diesel generators assumed as $150K per annum, including testing, maintenance and fuel and supply contracts. Allowance for additional parts costs and repairs has been assumed as $300K every 5 years.

Table 20: Option 3 Opex, relative to do nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Opex	0.00	-0.48	-0.47	-0.44	-0.42	-1.81	-9.31

Source: AusNet analysis

3.7.2. Benefits

75% of the baseline benefits have been assumed based on the diesel generators being able to operate as a backup only when the REFCL is in bypass mode.

The benefits are shown in Table 21.

Table 21: Option 3 Benefits, relative to do nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Benefits	-	-	0.56	0.54	0.52	1.62	9.58

Source: AusNet analysis

3.7.3. Summary

The benefits of the diesel generator option are limited as the diesel generators cannot be used in island mode in the times when REFCL protection is required on the 22kV polyphase network. This is due to the diesel generator microgrid section not being REFCL protected when it is in island mode (i.e. when a feeder outage occurs).

Other considerations:

- Noise may be a concern depending on the location of the generators.
- Diesel fuel management and the associated safety and fire risks.
- Some of the cost may be offset by a third party lease agreement for use of the diesel generators for providing capacity to the electricity market at peak times.

The cost and benefit summary (relative to the base case) is shown in Table 22. This option has a positive NPV, however it is subject to the considerations noted above.

Table 22: Option 3 Summary, relative to do nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	8.79	5.06	-0.47	-0.44	-0.42	12.52	8.60
Benefits	-	-	0.56	0.54	0.52	1.62	9.58
						NPV	0.98

Source: AusNet analysis

3.8. Option 4: Proposed Euroa express feeder with a remote REFCL changeover station

This section investigates the proposed Euroa express feeder with a remote REFCL changeover station in further detail.

3.8.1. Cost

3.8.1.1. Capex

The Capex assumptions for the proposed Euroa express feeder with a remote REFCL changeover station are shown below:

- 45kms between Benalla zone substation and Euroa
- Allow 2km allowance for deviations to direct road-based line route.
- Total 47kms: Assume 47 kms of overhead line.
- Switch costs based on AusNet's unit rates.
- No costs for easements have been assumed.
- Allowances for protection and control works included.
- No costs for three phase voltage regulators have been assumed. These may be required following detailed analysis.
- Design costs estimated at 4% of construction costs.
- Subcontractor indirect costs of 10%.
- Project management and construction management costs applied at 8% of design and construction costs.
- Risk of 10% added to direct costs.

The capital cost estimate is shown in Table 23 and the yearly capex is shown in Table 24.

Table 23: Option 4 Euroa express feeder with a remote REFCL changeover station, capital cost estimate

	Item	$m, FY2024
Capex	47kms of 22kV overhead line	16.6
	Allowance for protection works at Benalla and Remote REFCL site	0.2
	1 x ACR/Remote controlled gas insulated switch	0.1
	6 x Remote controlled gas insulated switches	0.2
	Allowance for control integration	0.3
	Sub-total - construction costs	17.4
	Design	0.7
	Subcontractor indirect costs	1.8
	Project management and construction management	1.4
	Total cost excluding risk allowance	21.4
	Risk	2.1
	Total	**23.5**

Replacement cost timing

Not included. New assets assumed to have a 50 year life.

Table 24: Option 4 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	14.09	8.90	-	-	-	22.99	22.99

Source: AusNet analysis

3.8.1.2. Opex

The Opex cost relative to the do nothing case is shown in Table 25. This value includes O&M costs associated with the new feeder assumed as $50K per annum for marginal increases in inspection and minor defect rectification.

Table 25: Option 4 Opex, relative to do nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Opex	-	-0.53	-0.58	-0.55	-0.52	-2.19	-11.75

Source: AusNet analysis

3.8.2. Benefits

This option will achieve the full Euroa township (and downstream of Euroa) benefits, excluding the low duration that both the BN11 and express feeders will experience a fault concurrently.

This option will also remove the demand constraint as it is proposed that the new feeder picks up part of the Euroa and BN004 network (as per Figure 2) using spare capacity from the BN zone substation REFCL (during normal operation).

The benefits (using the AER VCR values) are shown in Table 26 and the benefits (using the residential QCV) are shown in Table 27.

Table 26: Option 4 Benefits, relative to do nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Benefits	-	0.39	0.75	0.72	0.69	2.55	13.16

Source: AusNet analysis

Table 27: Option 4 Benefits (using AusNet Residential QCV), relative to do nothing case (using AusNet Residential QCV) ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Benefits	-	0.46	0.88	0.85	0.81	3.00	15.63

Source: AusNet analysis

3.8.3. Summary

This option is NPV positive as indicated in Table 28 and Table 29 and it maintains REFCL compliance as it uses the remote REFCL for the backup feeder using a changeover scheme.

Table 28: Option 4 Summary, relative to do nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	14.09	8.37	-0.58	-0.55	-0.52	20.80	11.24
Benefits	-	0.39	0.75	0.72	0.69	2.55	13.16
						NPV	**1.92**

Source: AusNet analysis

Table 29: Option 4 Summary (using AusNet Residential QCV), relative to do nothing case (using AusNet Residential QCV) ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	14.09	8.37	-0.58	-0.55	-0.52	20.80	11.24
Benefits	-	0.46	0.88	0.85	0.81	3.00	15.63
						NPV	**4.40**

Source: AusNet analysis

4. Preferred option and sensitivity testing

A Benalla to Euroa express feeder with a remote REFCL changeover station is the preferred solution to address the long radial network topology and demand constraint issues on BN11. Based on the NPV comparison in section 4.1 and sensitivity analysis in section 4.2 it is considered critical to seek funding for this program to improve outcomes for customers in the BN11 supply area.

4.1. NPV comparison

Comparing the base case to the four credible options, it can be seen in Figure 9 that option 3 and option 4 are viable options from an NPV perspective, with option 4 preferred.

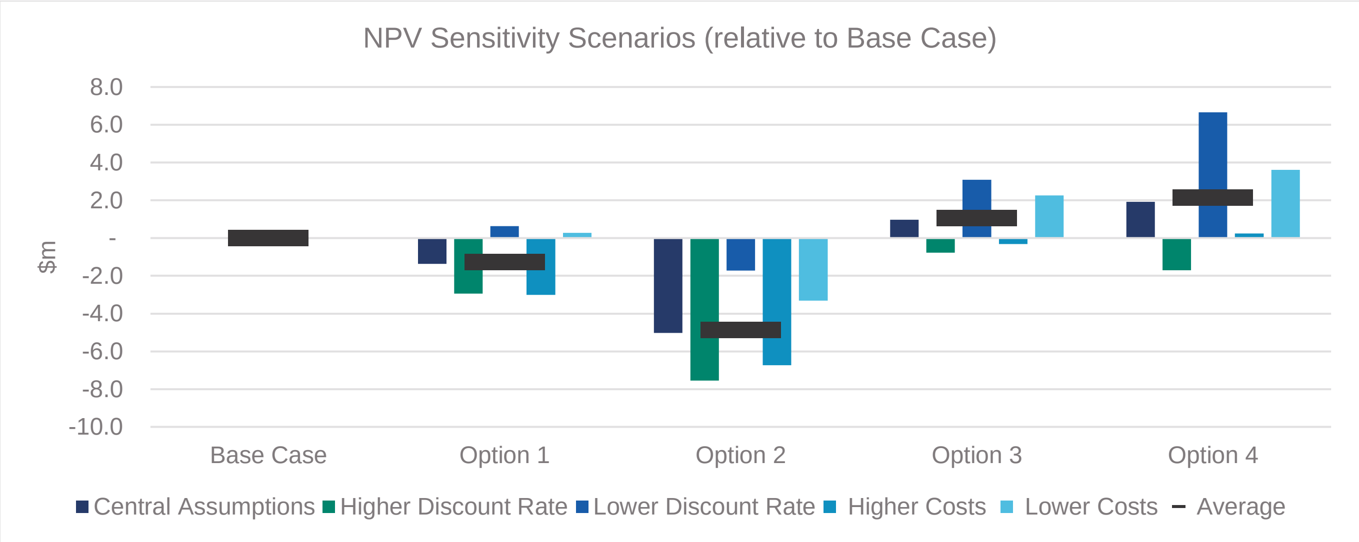

Figure 9: Net Present Values for the credible options using the AER VCR.

The four credible options are also compared against the base case in Figure 10 which includes the AusNet residential QCV in place of the AER VCR value. In this assessment, option 3 and 4 are viable options, with option 4 preferred.

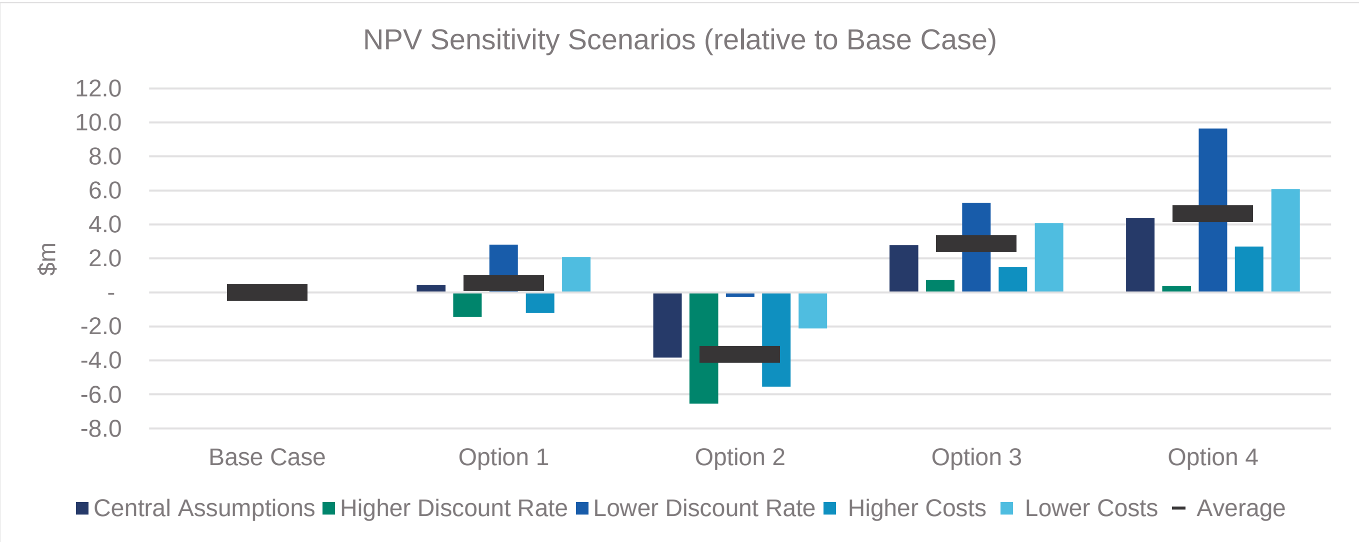

Figure 10: Net Present Values for the credible options using the AusNet residential QCV.

4.2. NPV sensitivity

The sensitivity on the preferred option (number 4) is favourable in all cases as indicated in Table 30 and Table 31.

Table 30: Net Present Value ($m, 2023-24 dollars)

	Central assumptions	Higher WACC	10% increase in capex	Comments
Do nothing	-	-	-	
Option 1 – New BESS for Euroa	-1.37	-2.95	-3.01	
Option 2 – Partial supply of BN11 load from RUBA12 and MSD2	-5.03	-7.55	-6.74	
Option 3 – Euroa diesel generators	0.98	-0.77	-0.31	
Option 4 – Proposed Benalla to Euroa express feeder with a remote REFCL changeover station	1.92	-1.71	0.23	This is the preferred option as it maximises the NPV, and it is a technically prudent solution.

Source: AusNet analysis

Table 31: Net Present Value (using AusNet Residential VCR value) ($m, 2023-24 dollars)

	Central assumptions	Higher WACC	10% increase in capex	Comments
Do nothing	-	-	-	
Option 1 – New BESS for Euroa	0.44	-1.43	-1.20	
Option 2 – Partial supply of BN11 load from RUBA12 and MSD2	-3.82	-6.54	-5.53	
Option 3 – Euroa diesel generators	2.78	0.74	1.49	
Option 4 – Proposed Benalla to Euroa express feeder with a remote REFCL changeover station	4.40	0.38	2.71	This is the preferred option as it maximises the NPV, and it is a technically prudent solution.

Source: AusNet analysis

5. References

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