AusNet

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

Business case: Worst Served Feeders Program

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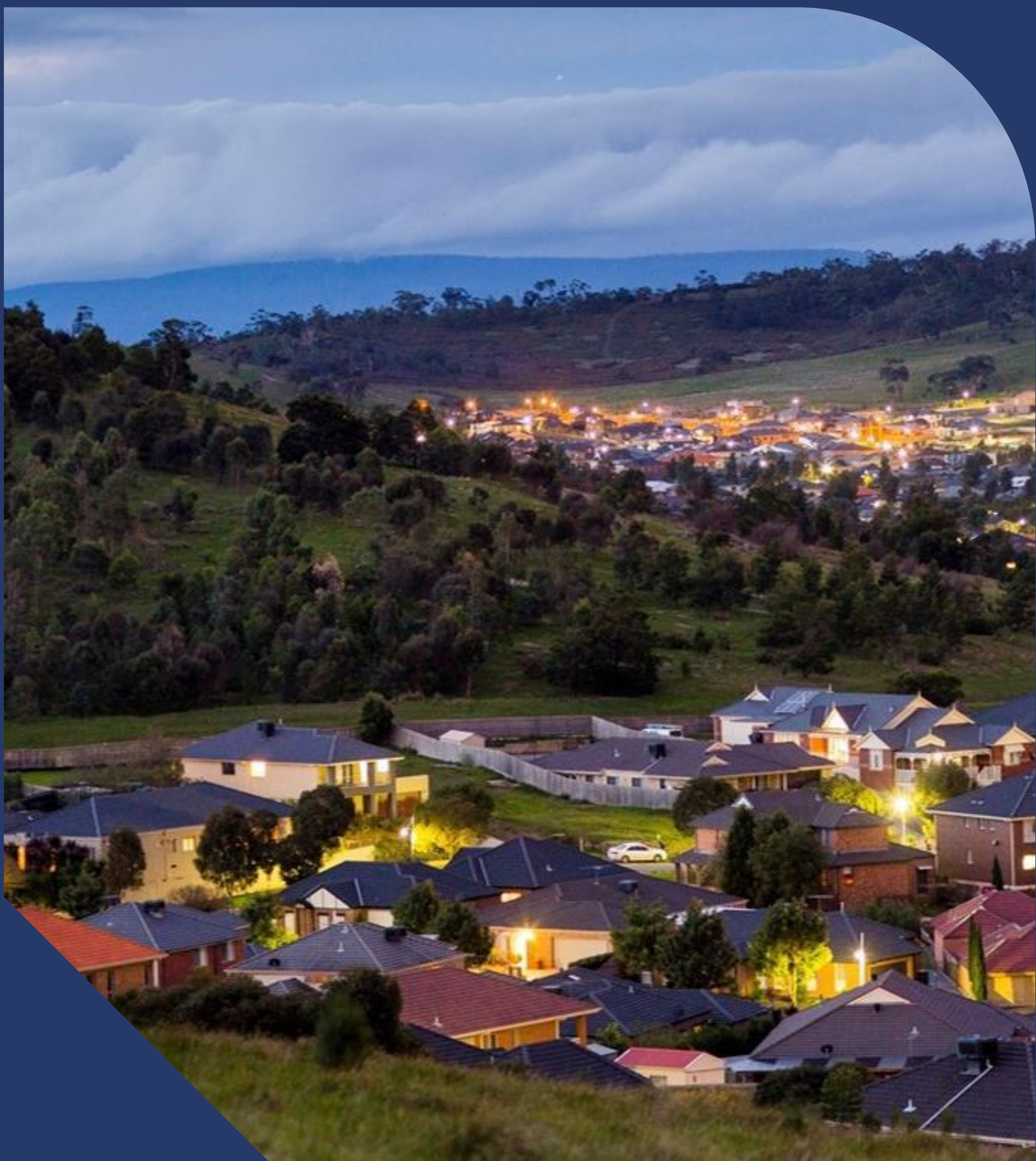

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1. Executive summary

AusNet has worked in partnership with customers to develop a Worst Served Feeders program to improve the electricity service to the most outage impacted, vulnerable and remote customers in AusNet's distribution network area.

This program was developed in collaboration with AusNet's electricity availability customer panel (**EACP**) over a 12-month period starting in early 2023, with the Australian Energy Regulator (**AER**) observing the meetings.

The objective of the program is to improve the electricity service to customers with historic high outage impact, vulnerability and remoteness, and this is strongly aligned with our regulatory requirements via the:

- targeting of *inadequately level of service customers* as defined by the Australian Energy Regulator[1] and recommended by the Australian Energy Market Commission (**AEMC**)[2].
- ensuring that AusNet meets its obligations under the *Victorian Electricity Safety Act 1998* to minimise as far as practicable, hazards/risks to public safety, including risks that arise through outages to the electricity supply.
- approach taken to meet reasonable customer expectations of reliability of supply as defined in the Electricity Distribution Code of Practice (**EDCoP**)[3].

Given AusNet's regulatory obligations and customer input from the EACP, AusNet believes it is incumbent on it to seek funding for this program to improve outcomes for inadequately served customers in regional communities.

AusNet also recognises that it must be prudent in its approach and therefore we jointly designed the Worst Served Feeders program with the EACP based on the following criteria:

- Worst served feeders are determined using the Inadequately Served Customer measure.
- Adjustments are made to exclude major event days (**MEDs**)and reflect average performance over a 5-year timescale.
- Secondary criteria are applied to qualitatively assist with the prioritisation of worst served feeders.

Applying the prudency criteria above resulted in ten high voltage feeders in the AusNet network being classified as "Worst Served." Customers on these high voltage feeders (shown in Figure 1) experience outages greater than four times the AusNet average; these customers are also vulnerable compared to the AusNet average based on the Socio-Economic Indexes for Areas (**SEIFA**)[4] data; and the majority of feeders are classed as remote as defined by the Accessibility/Remoteness Index of Australia (**ARIA+**)[5].

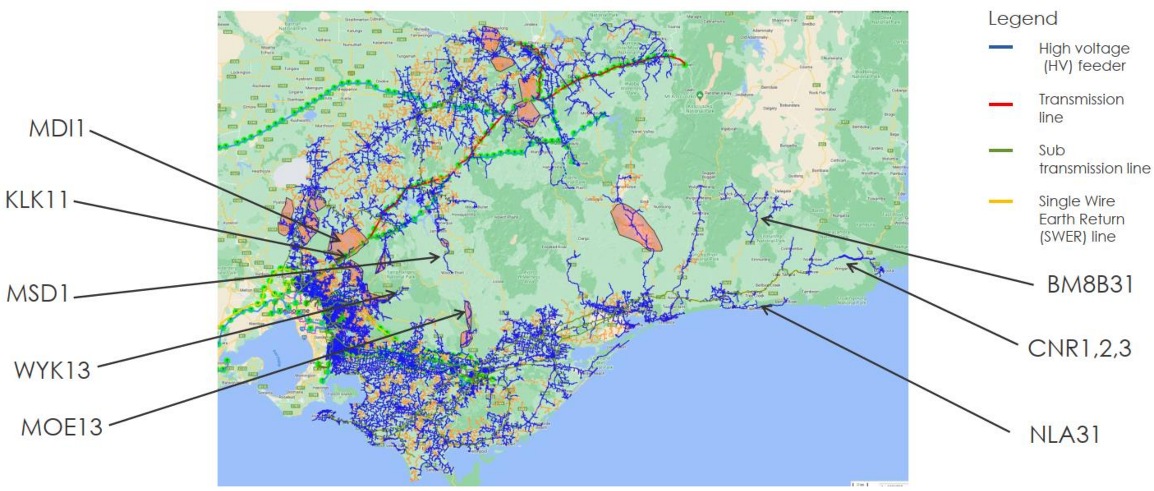


Figure 1: Ten worst served feeders on the AusNet network as decided by the EACP.

[1] Distribution Reliability Measures Guideline, Section 3.2, Australian Energy Regulator, August 2022
[2] Review of Distribution Reliability Measures Final Report, Section 6, Australian Energy Market Commission, 5 September 2014
[3] Electricity Distribution Code of Practice version 2, 1 May 2023, clause 13.3.1.
[4] Socio-Economic Indexes for Areas (SEIFA) is a product developed by the ABS that ranks areas in Australia according to relative socio-economic advantage and disadvantage. The indexes are based on information from the five-yearly Census, source: https://www.abs.gov.au/websitedbs/censushome.nsf/home/seifa
[5] The Accessibility/Remoteness Index of Australia (ARIA+) is the leading Australian indicator of remoteness. For the last two decades, it has been the official classification of remoteness used by the Australian Bureau of Statistics (ABS), source: https://able.adelaide.edu.au/housing-research/data-gateway/aria

In the ten feeder supply areas, AusNet considered solution options to prudently and efficiently improve the long-term reliability outcomes for customers.

AusNet's approach included:

- Identification of the problems on each feeder using five years of historical outage information, excluding Major Event Days (**MEDs**).
- Credible solution identification and development using network information, engineering input and historical unit costs.
- An economic valuation of the customer benefits (excluding MEDs) based on the energy not served 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 NPV analysis, customer considerations and a sensitivity analysis using variable discount rates and costs.

The preferred solutions are grouped as a Worst Served Feeder program of works as shown in Table 1.

Table 1: Worst Served Feeder Program Summary ($m, 2023-24 dollars[6])

Area	Feeder(s)	Preferred solution	FY27-FY31 Capex, $m
Bendoc	BM8B31	Installation of two remote controlled gas switches.	0.16
Cann River	CNR1, CNR2, CNR3	Augmentation in Cann River to extend the NLA31-CNR3 tie.	2.52
Kinglake	KLK11	Additional supply to the end of the Kinglake township and remote controlled gas switches on the north leg of KLK11.	1.98
Murrindindi	MDI1	SWER sectionalisation.	0.21
Moe	MOE13	New feeder tie to MOE21.	2.34
Mansfield	MSD1	10kms of targeted express overhead sections between Macs Cove and Kevington.	6.95
Newmerella	NLA31	New feeder tie from the NLA31-CNR3 northern leg from Brodribb River to Marlo.	3.07
Woori Yallock	WYK13	Extend the adjacent WYK23 feeder to East Warburton as a further backup supply and to increase sectionalisation.	6.26
		Total cost of the program	**23.49**

In addition to the individual feeder assessment, AusNet also assessed the NPV of the Worst Served Feeder program of works as shown in Table 2. The table includes the discounted total cost and total benefits over the full 30 year assessment period. The net present value is also shown and it has been calculated using the discounted total costs and benefits over the assessment period.

[6] Capex values are undiscounted.

Table 2: Worst Served Feeder Program Cost-Benefit Summary ($m, 2023-24 dollars)

	FY27 to FY31 (undiscounted)			Full assessment period (discounted)				
	Costs			Costs	Benefits and NPV: AER VCR Values		Benefits and NPV: AER VCR values for business and QCV for residential customers	
	Capex	Opex	Total cost	Total cost	Total benefits	NPV AER VCR Values	Total benefits	NPV AER/QCV Values
Do nothing	0.0	8.36	8.36	25.49	-104.58	-130.08	-145.94	-171.44
Worst Served Feeder Program	23.49	6.51	30.00	16.35*	20.62*	**4.27***	28.75*	**12.40***

*Source: AusNet analysis, *relative to Do nothing case.*

The customer-AusNet led Worst Served Feeder program of works is both prudent based on the EACP criteria and efficient for customers based on the favourable cost-benefit analysis present in Table 2.

Considering the prudency and proven efficiency of the proposed program, AusNet's regulatory obligations and customer inputs from the EACP, AusNet considers that it is critical to seek funding for this program to improve outcomes for inadequately served customers within AusNet's supply area. Electricity is an essential service for customers and it is critical to the health of AusNet's customers and for public safety, therefore it is important that we go as far as practicable to improve the service for customers on AusNet's worst served feeders.

2. Introduction

2.1. Background

The AusNet electricity distribution network covers the eastern part of Victoria and includes assets that extend to remote and vulnerable/low socio-economic areas. The network has developed based on customer connections and probabilistic network planning and includes areas that are both electrically and geographically remote.

AusNet has committed to improve reliability for regional communities and has consistently received support from customers to do so. Therefore, AusNet is proposing a program to invest to improve outcomes for customers on AusNet's worst served feeders.

2.2. Problem definition

The customers in AusNet's electrically remote areas experience greater outage impacts than urban customers due to the:

- Higher likelihood of faults due to greater network exposure to weather, vegetation, lightning and other fault causes correlated with the longer length of circuit between the supply and the customer.
- Higher consequence of an outage due to the lower availability of back-up supplies from adjacent feeders; lower sectionalisation and penetration of automation, meaning that more customers are impacted per fault event; and challenging terrain meaning that fault finding and repair can take longer than a shorter urban network.

AusNet also recognises that Victoria's climate is changing and this is backed by evidence from the Victorian Government[7]. This change could increase the likelihood of faults for electrically remote customers and AusNet believes that the 2026-2031 period is the right time to invest to improve customer outcomes on worst served feeders.

The problem has been defined using regulatory requirements and input from AusNet's electricity EACP (as described in section 3) and it is confined to:

- Worst served feeders determined using the Inadequately Served Customer measure, excluding major event days (MEDs)and reflective of the average performance over a 5-year timescale.
- EACP agreed additional secondary criteria (including vulnerability and remoteness) applied to qualitatively prioritise feeders.

2.2.1. 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.

2.3. Objective of the solution

The objective of the solution is to improve the electricity service to heavily outage impacted, vulnerable and remote customers on ten worst served feeders in the AusNet electricity supply area.

[7] https://www.climatechange.vic.gov.au/victorias-changing-climate

3. Regulatory inputs and engagement to achieve the optimal program

3.1. Regulatory requirements

3.1.1. Inadequately served customers

In response the Australian Energy Market Commission's recommendation, the Australian Energy Regulatory introduced an arrangement to identify customers who experience an inadequate level of reliability. The following definition now applies:

Inadequate level of service customer means a customer experiencing greater than 4 times the Network average for unplanned SAIDI on a three-year rolling average basis compared with a network average customer[8].

Distribution Network Service Providers (**DNSPs**) must report on inadequate level of service customers annually.

3.1.2. As far as practicable (AFAP)

As far as practicable (**AFAP**) is established in the energy safety act as the test to be applied in a Safety Case to show that the risk control efforts made by the Licensed Network Operator/Owner are adequate for meeting its statutory general duties and obligations.[9]

As stated in the Electricity Safety Act "A major electricity company must design, construct, operate, maintain and decommission its supply network to minimise as far as practicable, hazards/risks to public safety, damage to property and against bushfire danger."[10]

3.1.3. Customer expectations of reliability of supply

Under clause 13.3.1 of the Electricity Distribution Code of Practice (**EDCoP**), a distributor must meet reasonable customer expectations of reliability of supply.[11]

3.1.4. Summary of our regulatory requirements

Working under the AFAP requirements in the Electricity Safety Act and the expectations in the EDCoP, we believe it is critical that we seek funding to improve outcomes for inadequately served customers. Electricity is an essential service for customers and it is critical to the health of our customers and for public safety.

3.2. Customer collaboration to define worst served customers

AusNet worked with the EACP, with the oversight of the AER, to develop criteria for worst served customers. A two-phased assessment was proposed to AusNet's customer panel which included:

[8] Distribution Reliability Measures Guideline, Australian Energy Regulator, August 2022.
[9] Energy Infrastructure Safety Management Policy, Energy Safe Victoria, December 2019.
[10] Section 98, *Electricity Safety Act, 1998*.
[11] Electricity Distribution Code of Practice, Essential Services Commission,

(1) Using a measurement of poor reliability as the primary criterion to identify worst served customers/ feeders

(2) Applying several secondary criteria to prioritise customers/ feeders identified in step 1.

3.2.1. Primary criteria

The EACP agreed to the use of the Inadequately Served Customers [ISCs] definition, as described in section 3.1.1.

3.2.2. Secondary criteria

AusNet presented several secondary criteria including vulnerability, remoteness, life support customer prevalence and employers of community significance. The vulnerability and remoteness categories included benchmark indices, life support customers were considered and employers of significance was considered with a more open description. The criteria are further described below:

Vulnerability

The Socio-Economic Indexes for Areas (SEIFA) are used by researchers, policymakers, and community organisations to understand socio-economic patterns, identify areas in need of targeted interventions or resources, and inform policy decisions at various levels of government.

Remoteness

The Accessibility/Remoteness Index of Australia (ARIA+) is used by government agencies, researchers, and policymakers to understand the geographical distribution of services and to inform planning and resource allocation decisions. It helps identify areas that may require additional support or investment to bridge the accessibility gap and improve service provision in remote and very remote regions of Australia.

Life Support Customer Prevalence.

The life support customer provisions in the EDCoP are intended to support the most vulnerable members of society with managing loss of supply to their homes and medical equipment. However, AusNet recognised and supported the EACP's suggestion to ensure that, where opportunities to improve reliability are explored across our network, consideration was given to how we might support our most vulnerable customers through the provision of more reliable supply.

Employers of community significance.

Recognising the broader social and economic impact of supply interruptions to regional major employers and large businesses, AusNet also proposed to include assessment criteria that identifies feeders and network locations where at least one employer may have particular significance to the community. This could be measured as the number of organisations:

• With employee count – either total employees or as a proportion of the local population - exceeding a particular threshold (notwithstanding the limitations of publicly available data); and

• With energy consumption or demand exceeding a particular threshold, to demonstration the degree of reliance on reliable electricity supply.

3.2.3. Application of the primary and secondary criteria

AusNet worked with the EACP, informing the AER through its engagement program, to further define the criteria for worst served customers. Extracts of the slides presented to the EACP are shown in Figure 2 and Figure 3. The EACP considered the four methods presented and selected Method four as the most prudent. Method four identifies Worst Served Feeders using the Inadequately Served Customer measure, adjusted to exclude major event days (MEDs)and it reflects the average performance over a 5-year timescale. The remoteness, vulnerability and life support customer indices are shown Figure 2 for the different methods.

Summary | Relationship between methodology and feeder characteristics

DISCLAIMER: All analysis is based on data up to and including FY23.

	AusNet Average/Total	METHOD 1 3-year average, incl. MEDs	METHOD 2 5-year average, incl. MEDs	METHOD 3 3-year average, excl. MEDs	METHOD 4 5-year average, excl. MEDs
Number of Inadequately Served Feeders (ISF)	*358 (Total network feeders)*	19	22	17	10
Customers	*795,904* Residential - 80% Farm – 12% Commercial – 6% Industrial – 1% Unknown – 1%	42,049 Residential - 82% Farm – 11% Commercial – 6% Industrial – 1% Unknown – 1%	43,917 Residential - 76% Farm – 15% Commercial – 8% Industrial – 1% Unknown – 1%	19,107 Residential - 80% Farm – 12% Commercial – 6% Industrial – 1% Unknown – 1%	10,659 Residential - 80% Farm – 11% Commercial – 7% Industrial – 1% Unknown – 1%
Average USAIDI (minutes off supply)	*205 (FY23 only)*	607	479	159	171
Remoteness (ARIA+) *Higher value = more remote*	*1.04*	0.5	0.8	1.4	1.9
Vulnerability (SEIFA Index) *Lower value = more vulnerable*	*1016*	1037	1020	984	955
Life support customers (per 100 customers)	*2.1*	2.0	2.1	2.0	2.4

Note: Customer percentages are rounded and therefore may add to more than 100%

Figure 2: Extract of the Worst Served Feeder methodology slides presented to the EACP (statistics)

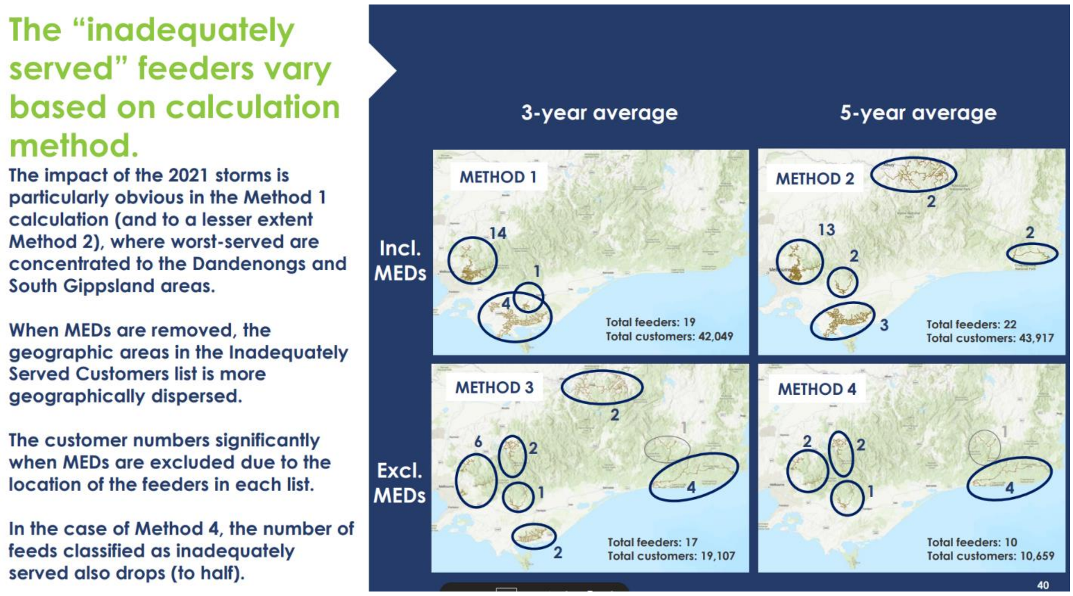


Figure 3: Extract of the Worst Served Feeder methodology slides presented to the EACP (geographic view)

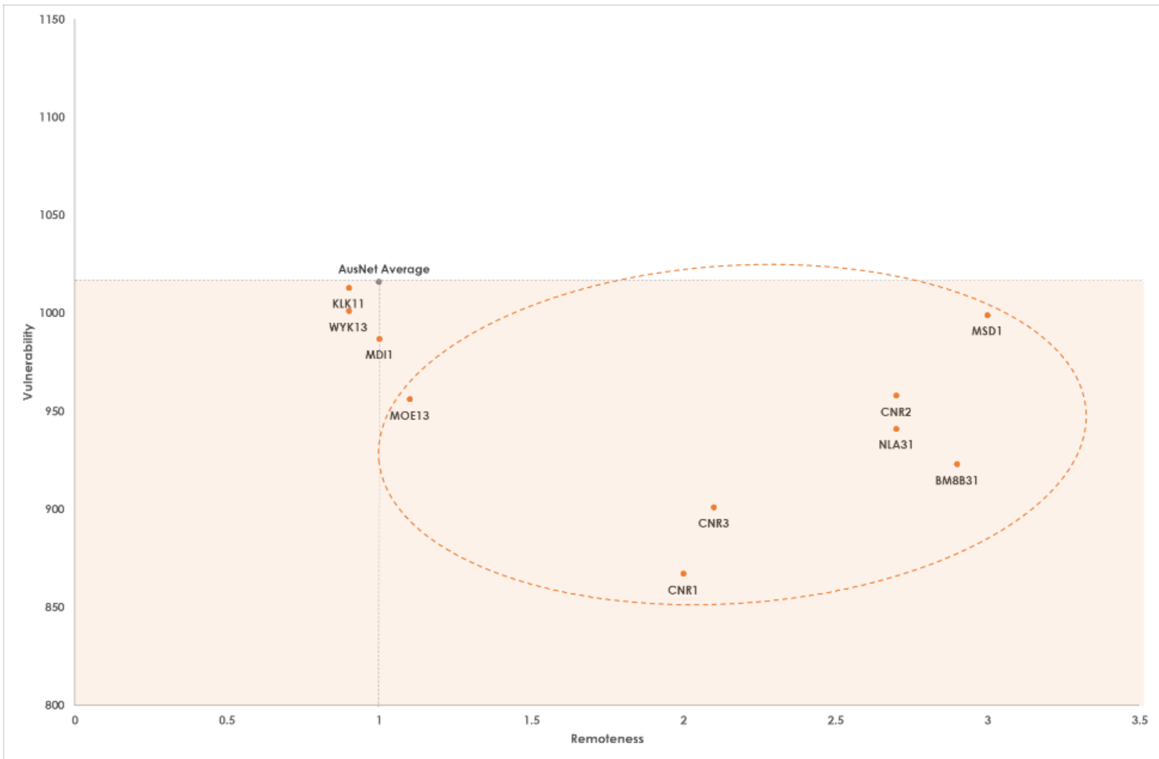
3.2.4. Summary of the worst served customers/ feeders agreement with the availability customer panel

The EACP decided that worst served feeders should be determined using the Inadequately Served Customer measure, adjusted to exclude major event days (MEDs)and reflect average performance over a 5-year timescale, with the secondary criteria to be applied qualitatively to assist with prioritisation of feeders.

Customers on the ten nominated high voltage feeders in Figure 1 experience outages greater than four times the AusNet average (as shown in Figure 4). Customers on these feeders are also vulnerable compared to the AusNet average and seven of the ten nominated feeders are classed as remote compared to the AusNet average (as shown in Figure 5).

Feeder location	Feeder code	USAIDI (avg. outage duration per customer per year)	USAIFI (avg. outages per customer per year)	Feeder customers
Cann River	CNR2	27.8 hrs	8.7	1,202
Bendoc	BM8B31	27.4 hrs	3.8	122
Cann River	CNR1	22.6 hrs	5.7	150
Moe	MOE13	16.4 hrs	7.1	728
Woori Yallock	WYK13	15.7 hrs	4.9	3,653
Cann River	CNR3	15.1 hrs	6.3	53
Murrindindi	MDI1	13.8 hrs	3.8	55
Mansfield	MSD1	12.7 hrs	3.9	2,219
Newmerella	NLA31	12.2 hrs	2.7	955
Kinglake	KLK11	12.2 hrs	4.3	1,525

Figure 4: Average unplanned outage duration time per annum for the ten targeted high voltage feeders.



- Orange shading shows the feeders that are more vulnerable than the AusNet average.
- The orange circle includes the feeders that are more remote than the AusNet average.

Figure 5: Vulnerability and remoteness of the customers of the ten targeted high voltage feeders.

3.3. Program options assessed

AusNet worked with the EACP, to obtain feedback on solution options for worst served customers. An extract of the early worst served customer program solution options is shown in Figure 6.

Figure 6: Worst served customer program solution option engagement.

The EACP determined that expenditure in the order of $25m was optimal to improve the outcomes on ten worst served feeders.

The solution options have been further refined and assessed since the EACP engagement and the most prudent and efficient Worst Served Feeder program is presented in sections 5 to 15 of this document.

4. Key assumptions and methodology

A net present value assessment was used to determine the best solution for the customers on each of the selected ten high voltage feeders. The key assumptions are detailed in Table 3.

Table 3: 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.	We used AER VCR Figures in 2023-24 dollars. VCR values have been applied to each feeder in accordance with the customer categories on each feeder.

Source: AusNet analysis

Additional assumptions are listed below:

- Feeders selected based on the criteria described in section 3.
- Five years of actual customer outage data used.
- Major Event Days have been excluded from the outage impact analysis.
- 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 4.1.
- 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[12].
- Operational costs associated with faults determined using historical actuals.

4.1. Do nothing calculation methodology

The economic impacts per annum under a do nothing scenario has been calculated using five years of historical actual outage data which provides the number of customers impacted per outage and outage durations, excluding Major Event Days (**MEDs**). Using these inputs, the value of each outage was calculated using the VCR applicable to the feeder under investigation, the application of the VNR, and the average kW per customer (for that feeder).

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 the feeder under investigation.

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.

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

- 6570kWh per annum is based on the Department of Climate Change, Energy, the Environment and Water typical average daily generation of 3.6 kWh[13] per kW of solar panels multiplied by 365 days multiplied by an assumed average system size of 5kW.

AusNet also reviewed the operational costs associated with the past five years of historical outages and historical guaranteed service level (GSL) costs on each of the feeders under investigation. Using this historical data, AusNet calculated the average operational cost and GSL impact per annum and used this value as an annual forecast cost in the do nothing scenario.

4.2. Methodology

This section provides an overview of AusNet's methodology for calculating the costs and benefits for each option on the feeders in the Worst Served Feeders program. This follows the "Do nothing calculation methodology" described in section 4.1.

The quantitative approach included:

- Credible solution identification and development using network information and engineering input.
- Calculation of solution cost estimates using historical unit costs and bottom up cost estimates.
- Identification of the number of customers to benefit from an intervention based on the proposed network topology (for the intervention) versus the existing network topology.
- Development of a customer minutes off supply (CMOS) benefit calculation to determine the future customer minutes off supply using the average fault frequency and duration in the relevant sections of the proposed feeder intervention, compared to the existing network topology.
- An adjustment to CMOS benefits for expected coincident event risks. For example, for a proposed new alternative supply line, AusNet has slightly reduced the CMOS benefit to account for cases when faults occur on both assets at the same time.
- An economic valuation of the customer benefits (excluding MEDs) was calculated using the percentage CMOS improvement compared to the economic valuation of the base case. As described in section 4.1, the base case economic calculation is based on the energy lost during network outages and the AER's value of customer reliability, the application of the VNR and GSLs. The benefits for each option are shown relative to the base case throughout this business case.
- A net present value assessment (**NPV**) for each proposed intervention against the base case (do nothing) using the parameters in section 4.
- Selection of a preferred option based on the NPV analysis, customer considerations and a sensitivity analysis using variable discount rates and costs.

The preferred solutions are grouped as a Worst Served Feeder program of works.

[13] 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.

5. Program of works for customers on our worst served feeders

The preferred solutions are grouped as a Worst Served Feeder program of works as shown in Table 4.

Table 4: Worst Served Feeder Program Summary ($m, 2023-24 dollars)

Area	Feeder(s)	Preferred solution	FY27-FY31 Capex, $m
Bendoc	BM8B31	Installation of two remote controlled gas switches.	0.16
Cann River	CNR1, CNR2, CNR3	Augmentation in Cann River to extend the NLA31-CNR3 tie.	2.52
Kinglake	KLK11	Additional supply to the end of the Kinglake township and remote controlled gas switches on the north leg of KLK11.	1.98
Murrindindi	MDI1	SWER sectionalisation.	0.21
Moe	MOE13	New feeder tie to MOE21.	2.34
Mansfield	MSD1	10kms of targeted express overhead sections between Macs Cove and Kevington.	6.95
Newmerella	NLA31	New feeder tie from the NLA31-CNR3 northern leg from Brodribb River to Marlo.	3.07
Woori Yallock	WYK13	Extend the adjacent WYK23 feeder to East Warburton as a further backup supply and increase sectionalisation.	6.26
		Total cost of the program	**23.49**

In addition to the individual assessment, we also assessed the NPV of the Worst Served Feeder program of works as shown in Table 5. Two program assessments are shown, assessment 1 includes benefits based on the AER VCR and assessment 2 includes benefits based using the AER VCR values for business customers and a substitute VCR value for residential customers. The substitute VCR value was determined from a willingness to pay survey and it determined that the value of outages to AusNet residential customers is $54.80 per kWh[14] which is higher than the AER residential VCR figure.

[14] AusNet Residential Quantitative Customer Value (QCV) in FY2024 $s.

Table 5: Worst Served Feeder Program Cost-Benefit Summary ($m, 2023-24 dollars)

	FY27 to FY31 (undiscounted)			Full assessment period (discounted)				
	Costs			Costs	Benefits and NPV: AER VCR Values		Benefits and NPV: AER VCR values for business and QCV for residential customers	
	Capex	Opex	Total cost	Total cost	Total benefits	NPV AER VCR Values	Total benefits	NPV AER/QCV Values
Do nothing	0.0	8.36	8.36	25.49	-104.58	-130.08	-145.94	-171.44
Worst Served Feeder Program	23.49	6.51	30.00	16.35*	20.62*	**4.27***	28.75*	**12.40***

*Source: AusNet analysis, * relative to Do nothing case*

The customer-AusNet led Worst Served Feeder program of works is both prudent and efficient based on the EACP criteria and the favourable cost-benefit analysis presented in Table 5.

Considering the prudency and proven efficiency of the proposed program, our regulatory obligations and customer input from the EACP, AusNet considers that it is critical to seek funding for this program to improve outcomes for inadequately served customers within AusNet's supply area. The assessment for the ten worst served feeders is shown in sections 6 to 13.

6. BM8B31

6.1. Identified need

Customers on the Bendoc BM8B31 feeder, in the north-east of Victoria, experience an average outage duration of 27.4 hours per annum. This is more than nine times the outage impact experienced by the average AusNet customer.

The BM8B31 feeder originates from the NSW border (as shown in Figure 8).

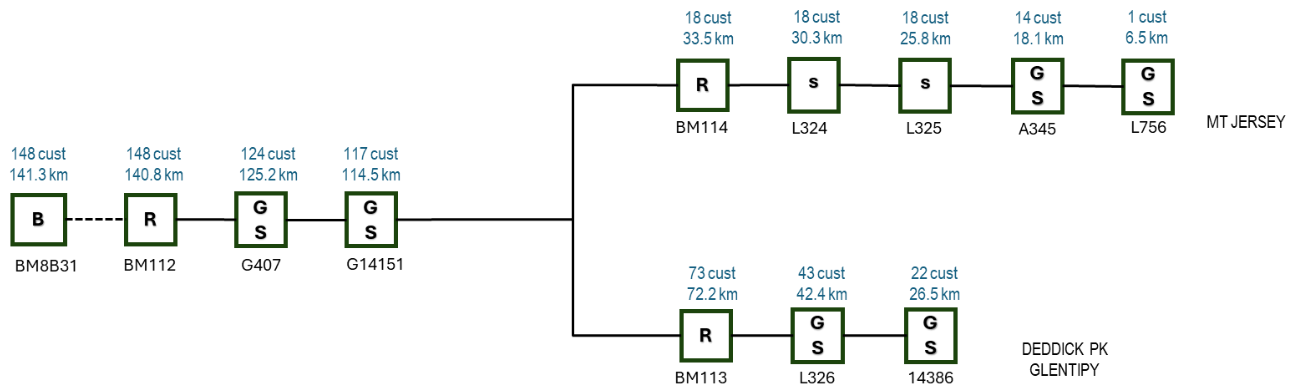


Figure 7: Representation of the BM8B31 high voltage feeder (Present state).

Figure 8: Map view of the BM8B31 feeder showing the Victorian and NSW border.

6.2. Options assessed

As shown in Figure 7, the BM8B31 feeder splits into two major sections which run west and south as shown geographically in Figure 8. There are also other BM8B feeders in the area. Given these characteristics, we considered the following options:

- Do nothing.
- Option 1: Installation of two remote controlled gas switches.
- Option 2: New feeder tie to BM8B32.

Other options considered but discounted include:

- New feeder tie to BDL41. This option was discounted as the length of new circuit required to tie the feeder to BM8B31 is almost double the circuit length required in option 2, resulting in a significantly higher cost for this feeder tie.
- Undergrounding: This option was discounted due to the high cost of undergrounding the length of this feeder at $801K per km and the low customer numbers per km on this feeder.
- Non-network solution: Stand Alone Power Systems (SAPS). A SAPS approach would require 148 customers to sign up and commit to non-network SAPS at approximately $40K per system[15]. The installation, future replacement and O&M costs would exceed the costs of options 1 and 2.

6.3. Do nothing

Customers on the Bendoc BM8B31 feeder will continue to experience an average economic impact of $100K per annum as shown in Table 6.

Table 6: BM8B31 Do nothing scenario ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	0.03	0.03	0.02	0.02	0.02	0.12	0.41
Energy at risk	-0.10	-0.10	-0.09	-0.09	-0.08	-0.46	-1.70
						NPV	**-2.11**

Source: AusNet analysis

Table 7: BM8B31 Do nothing scenario ($m, discounted, 2023-24 dollars) (using AusNet QCV Residential VCR)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	0.03	0.03	0.02	0.02	0.02	0.12	0.41
Energy at risk	-0.11	-0.11	-0.10	-0.10	-0.09	-0.50	-1.87
						NPV	**-2.28**

Source: AusNet analysis

[15] Source: https://offgridaustralia.com.au/faq/how-much-does-an-off-grid-system-cost/

6.4. Option 1: Installation of two remote controlled gas switches

The purpose of this Remote Controlled Gas Switches (RCGS) option is to minimise the number of customers impacted per sustained fault. As shown in Figure 9, the introduction of RCGS[16] splits the feeder into additional sections that can be quickly isolated for sustained faults using automation or control via the Network Control Room. Through operational control, customers upstream of new RCGS remain online when there is a sustained fault downstream of the new RCGS. Therefore, the CMOS saved is related to the number of customers upstream and the duration of the faults downstream of the new RCGS. This benefit has been modelled for the sections 1 and 2 (in Figure 9) which covers the impact of the new RCGS at G14151 and sections 3 and 4 which covers the new RCGS at A345 (in Figure 9). Section 5 (in Figure 9) has been excluded as that section is already covered by an ACR. Our review of the historical fault data also indicated that the BM113 section 5 experienced a lower level of faults compared to the other sections on the BM8B31 feeder and therefore the benefit of further sectionalisation is low.

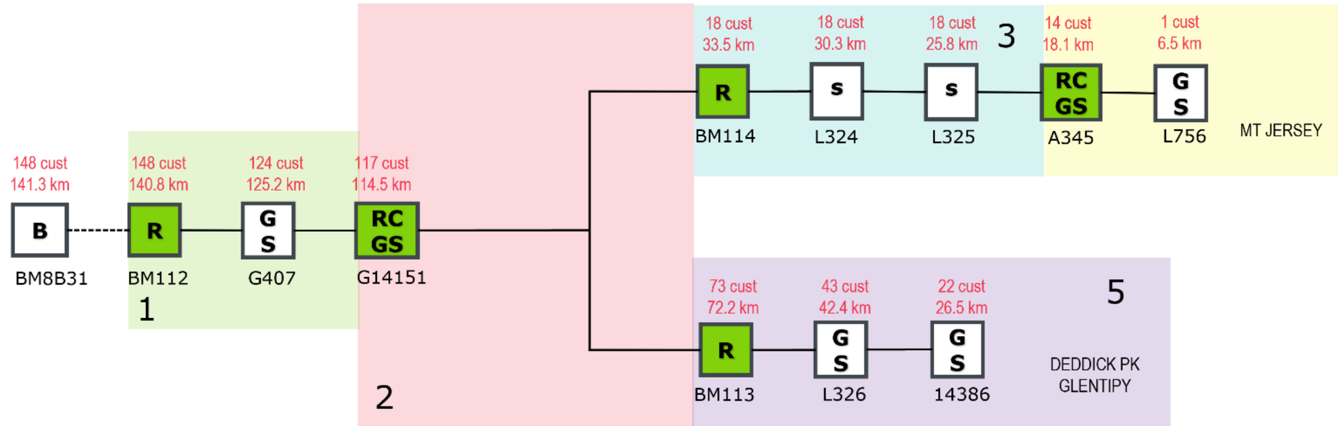


Figure 9: BM8B31 option 1 representation

6.4.1. Cost

6.4.1.1. Capex

Unit costs were used to develop the capital expenditure estimate for BM8B31 option 1. The scope of work includes:

- two new remote controlled gas switches (including remote fault indicators) at [CIC] each.
- remote location allowance of [CIC] per switch.

The capex estimate shown in Table 8. It is proposed that this project starts and finishes in FY27.

Table 8: BM8B31 Option 1 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	0.16	-	-	-	-	0.16	0.16

Source: AusNet analysis

6.4.1.2. Opex

Additional operating expenditure associated with option 1 has been estimated at 0.5% of the capex cost per annum as shown in Table 9.

[16] with additional remote fault indication.

Table 9: BM8B31 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	-	-0.01	-0.01	-0.01	-0.01	-0.03	-0.12

Source: AusNet analysis

6.4.2. Benefits

This option will provide benefits to 35 customers on the feeders and future customers that connect to the network in the areas of Delegate River and between Bonang and Goongerah along Bonang Road as estimated in Table 10. The alternative benefits, using AusNet QCV Residential VCR value, are also shown in Table 11.

Table 10: BM8B31 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	-	0.00	0.00	0.00	0.00	0.01	0.07

Source: AusNet analysis

Table 11: BM8B31 Option 1 Benefits, (using AusNet QCV Residential VCR), relative to Do Nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Benefits	-	0.00	0.00	0.00	0.00	0.02	0.08

6.4.3. Summary

Given the low cost of this option, and optimal targeting of feeder sectionalisation, it provides a positive NPV for customers as indicated in Table 12. The NPV using AusNet QCV Residential VCR value is also shown in Table 13.

Table 12: BM8B31 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	0.16	-0.01	-0.01	-0.01	-0.01	0.13	0.04
Benefits	-	0.00	0.00	0.00	0.00	0.01	0.07
						NPV	**0.03**

Source: AusNet analysis

Table 13: BM8B31 Option 1 Summary, relative to Do Nothing case (using AusNet QCV Residential VCR) ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	0.16	-0.01	-0.01	-0.01	-0.01	0.13	0.04
Benefits	-	0.00	0.00	0.00	0.00	0.02	0.08
						NPV	**0.04**

6.5. Option 2: New feeder tie to BM8B32

The introduction of a feeder tie offers a backup supply for customers when there is an outage on an upstream supply. This option proposes an 18 km overhead feeder tie (via roadways) to the nearest geographic location on the BM8B32 three phase 22kV network (as shown in Figure 10), which will result in a BM8B31 to BM8B32 tie as shown on Figure 11. The feeder tie will link to the BM8B31 feeder near the existing 14151 switch.

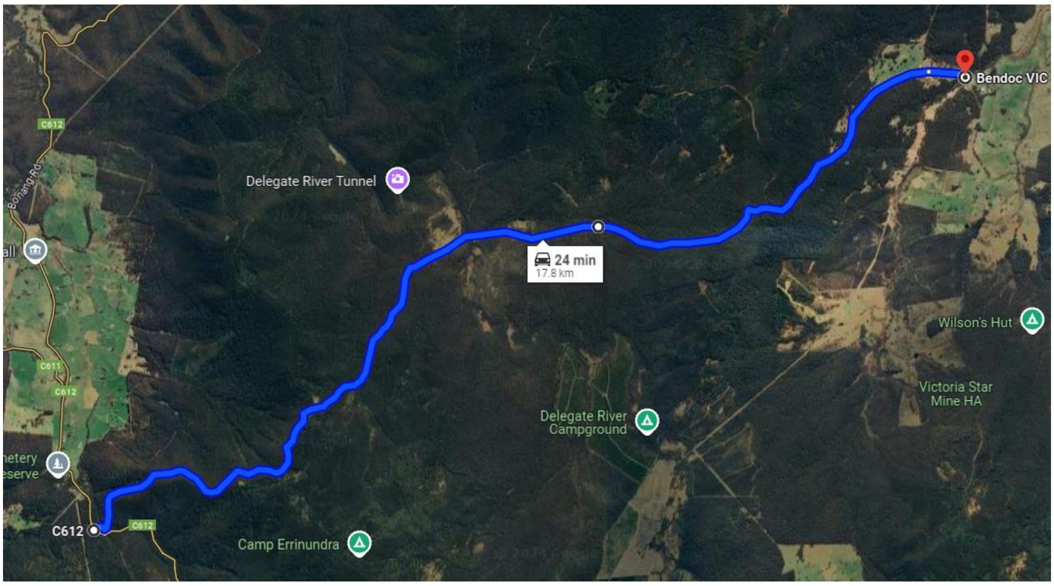


Figure 10: Route of new feeder tie between BM8B31 and BM8B32

Referring to Figure 11 and Figure 12, we can see that this solution will benefit customers downstream of G14151 if there is a fault upstream of this point as there is now an alternative source of electricity for downstream customers. The introduction of a new RCGS means that upstream customers also benefit for faults downstream of the existing G14151 device as shown in Figure 13.

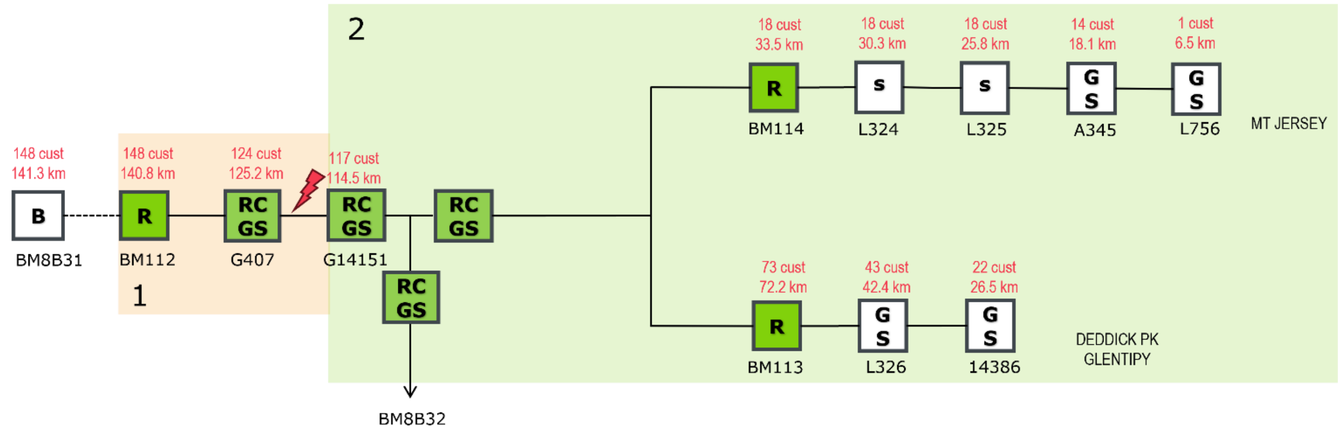


Figure 11: BM8B31 option 2 representation (fault in section 1 past G407)

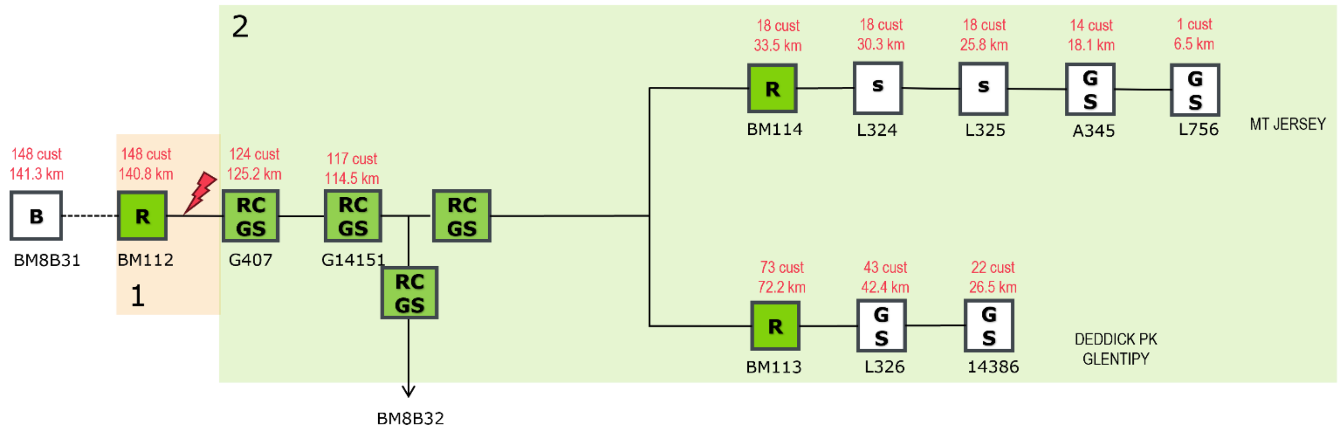


Figure 12: BM8B31 option 2 representation (fault in section 1 before G407)

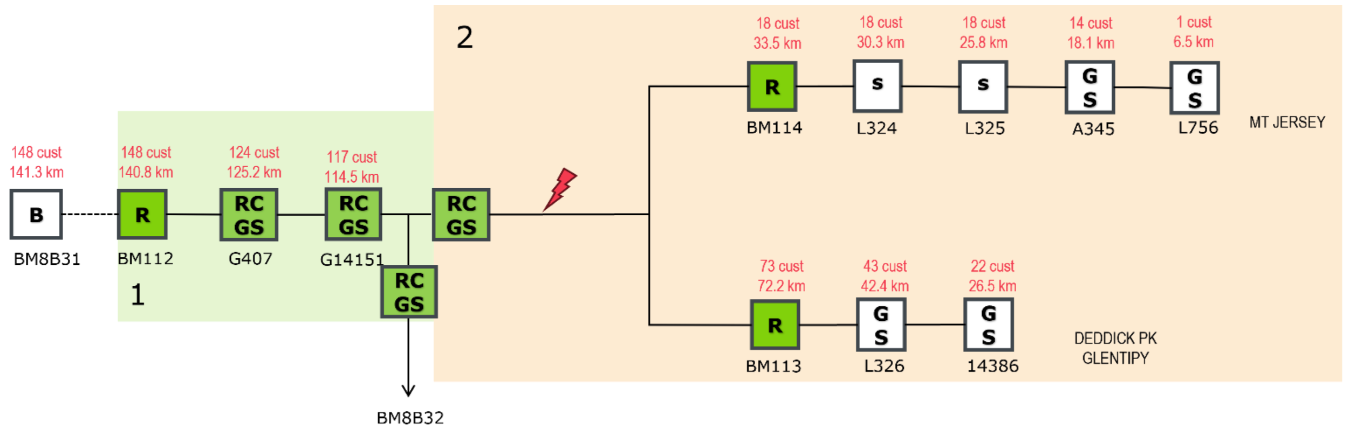


Figure 13: BM8B31 option 2 representation (fault in section 2)

6.5.1. Cost

6.5.1.1. Capex

We used unit costs to develop the capital expenditure estimate for BM8B31 option 2. The scope of work includes:

- 18 km of 22kV overhead line valued at [CIC] per km.
- four new remote controlled gas switches (including remote fault indicators) at [CIC] each.
- remote location allowance of [CIC] per switch.

The capex estimate is shown in Table 14. It is proposed that this project starts in FY27 and finishes in FY28.

Table 14: BM8B31 Option 2 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	4.14	3.93	-	-	-	8.07	8.21

Source: AusNet analysis

6.5.1.2. Opex

Additional operating expenditure associated with option 1 has been estimated at 0.5% of the capex cost per annum as shown in Table 15.

Table 15: BM8B31 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	-	-	0.02	0.02	0.02	0.06	0.32

Source: AusNet analysis

6.5.2. Benefits

All customers on the feeder will benefit from option 2 due to additional source of supply and feeder sectionalisation as shown in Table 16. The alternative benefits, using AusNet QCV Residential VCR value, are also shown in Table 17.

Table 16: BM8B31 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	-	-	0.04	0.04	0.04	0.13	0.72

Source: AusNet analysis

Table 17: BM8B31 Option 2 Benefits (using AusNet QCV Residential VCR), relative to Do Nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Benefits	-	-	0.05	0.05	0.04	0.14	0.79

6.5.3. Summary

The high cost of this option compared to the relatively low customer numbers and therefore economic benefits, means that this option is NPV negative as indicated in Table 18. The NPV using AusNet QCV Residential VCR value is also shown in Table 19.

Table 18: BM8B31 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	4.14	3.93	0.02	0.02	0.02	8.13	8.53
Benefits	-	-	0.04	0.04	0.04	0.13	0.72
						NPV	**-7.81**

Source: AusNet analysis

Table 19: BM8B31 Option 2 Summary, relative to Do Nothing case (using AusNet QCV Residential VCR) ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	4.14	3.93	0.02	0.02	0.02	8.13	8.53
Benefits	-	-	0.05	0.05	0.04	0.14	0.79
						NPV	**-7.74**

6.6. Preferred option (and sensitivity testing)

Option 1 provides an optimal solution by sectionalising the BM8B31 feeder using RCGS. The sensitivity on this solution is also favourable in all cases as indicated in Table 20.

Table 20: Net Present Value ($m, 2023-24 dollars)

	Central assumptions	Higher WACC	10% increase in capex	Comments
Do nothing	-	-	-	
Option 1 – Installation of two remote controlled gas switches	0.03	0.00	0.03	This is the preferred option under all scenarios
Option 2 – New feeder tie to BM8B32	-7.81	-7.80	-9.09	

Source: AusNet analysis

7. CNR1, 2, 3

7.1. Identified need

Customers on the Cann River feeders 1, 2 and 3, in the Gippsland area of Victoria, experience an average outage duration per annum of 22.6 hours, 27.8 hours and 15.1 hours respectively. This is between five to ten times the outage impact experienced by the average AusNet customer.

The geographic location of the three Cann River feeders is shown in Figure 14 and the feeder representations are shown in Figure 16, Figure 17 and Figure 18.

Customers on the Cann River feeders are supplied by an upstream 82 km radial 66kV sub-transmission line between Newmerella and Cann River as shown in Figure 15. The majority of this line traverses state forest and National Park and it experiences a high number of faults due to bark hitting the 66kV line.

Due to the location and nature of these incidents it can take many hours to respond and restore supply to CNR ZSS.

In the Mallacoota area, AusNet's existing Mallacoota Area Grid Storage (MAGS) device is able to island and supply the Mallacoota township (1113 customers) however there is no alternate supply to the balance of impacted customers in Cann River and the surrounding areas.

Figure 14: Map showing the Cann River feeders CNR1, CNR2 and CNR3

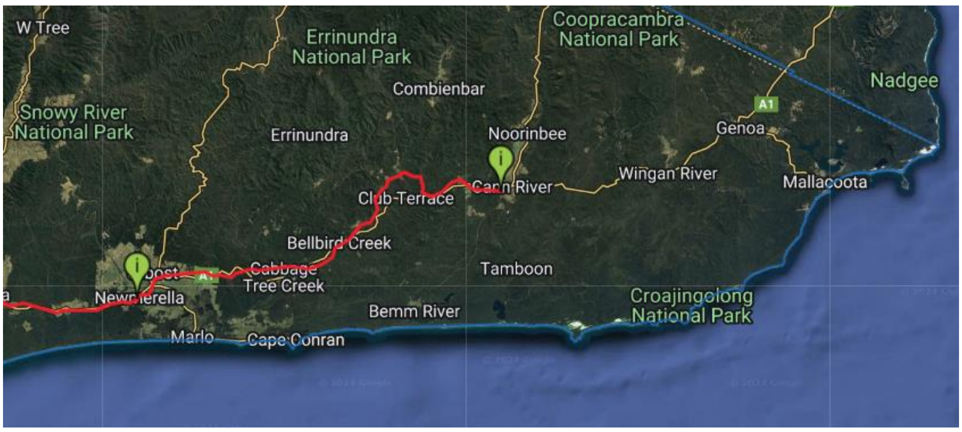


Figure 15: AusNet's 81 km radial 66kV sub-transmission line between Newmerella (NLA) and Cann River (CNR) traverses state forest and National Park

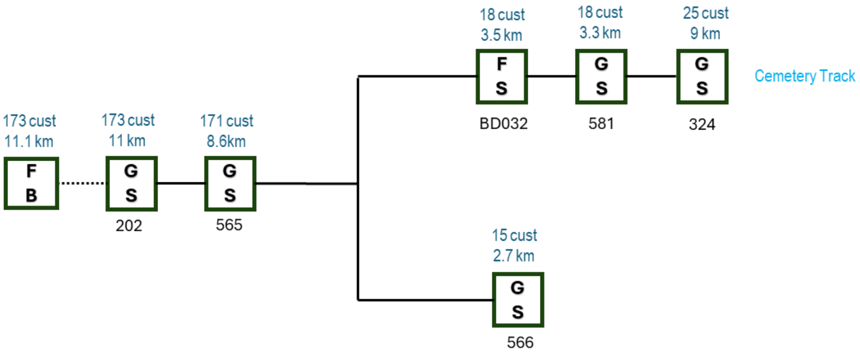


Figure 16: Representation of the CNR1 feeder

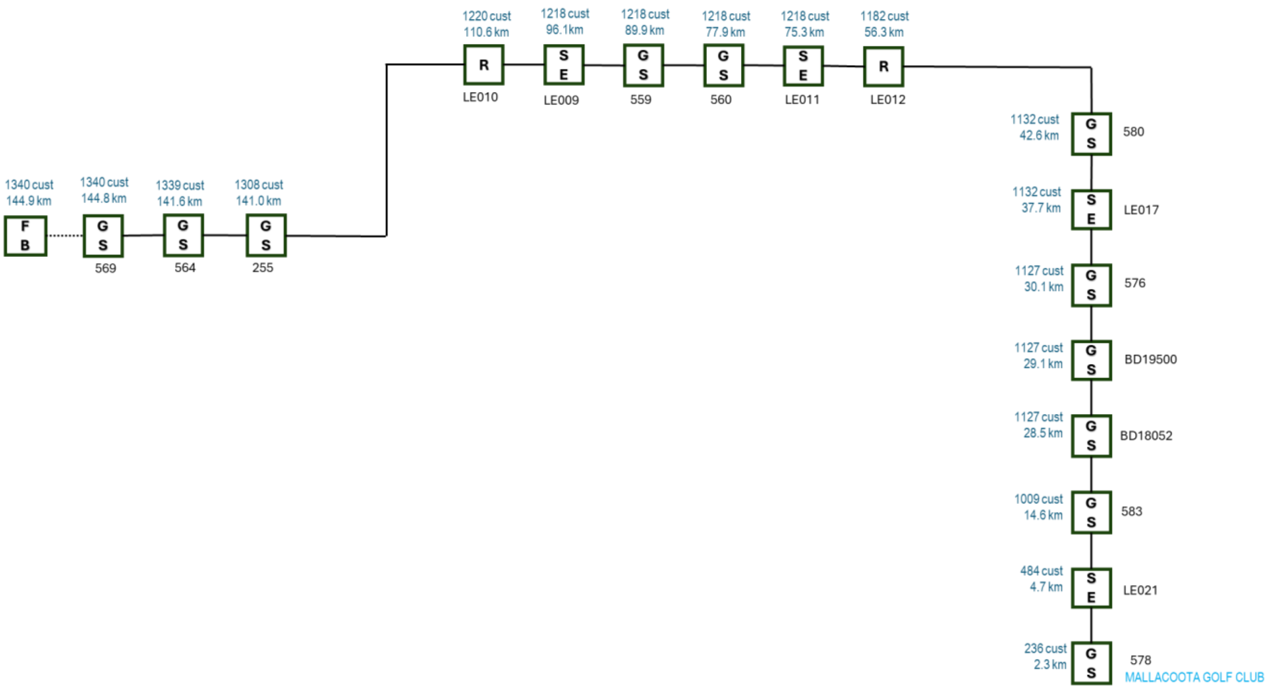


Figure 17: Representation of the CNR2 feeder

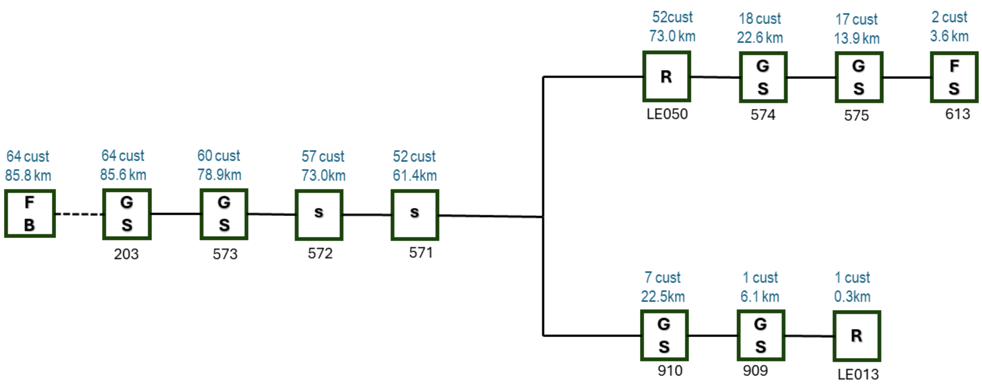


Figure 18: Representation of the CNR3 feeder

7.2. Options assessed

As identified in section 7.1, solving the 66kV radial supply challenge is a priority. Sectionalisation of the feeders has also been considered.

The customer outage heat maps (shown in Figure 19, Figure 20 and Figure 21) and historical outage data indicates that the current sectionalisation is appropriate for CNR 1, CNR2 and CNR3 as summarised here:

- small numbers of customers are impacted per fault on CNR1, except for one major outage in 2021 that affected nearly all of the customers on the feeder for an average of 15 hours.
- small numbers of customers are impacted per fault on CNR3 due to the back feed available via NLA31.
- MAGS is able to back up the major customer centre in Mallacoota.

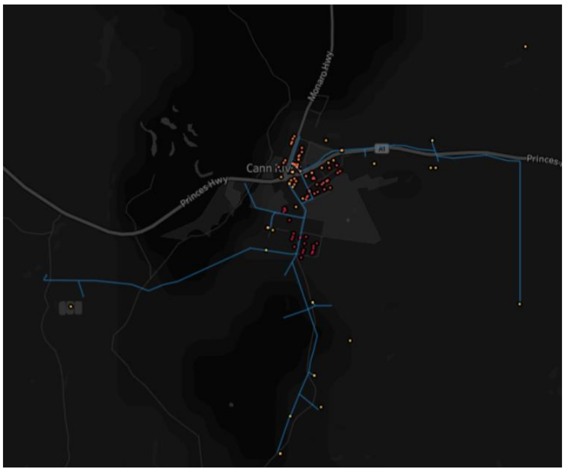


Figure 19: CNR1 customer outage heat map

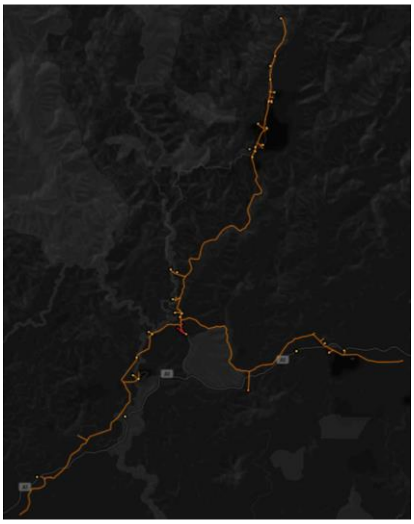


Figure 20: CNR3 customer outage heat map

Figure 21: CNR2 customer outage heat map

In summary, we considered:

- Option 1: Augmentation in Cann River to extend the NLA31-CNR3 tie to backup CNR1, part of CNR2 and CNR3.
- Option 2: Additional microgrid at Cann River.

Other options considered but discounted include:

- Undergrounding due to the high cost of undergrounding extremely long lengths of line.

7.3. Do nothing

Customers on CNR1, CNR2 and CNR3 will continue to experience approximately $2.2m of economic impacts per annum under a do nothing scenario. The costs in Table 21 also includes the operational costs of outages at the same level as the past five years.

Table 21: CNR1, 2, 3 Do nothing scenario ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	0.35	0.34	0.32	0.30	0.29	1.59	5.40
Energy at risk	-2.24	-2.14	-2.05	-1.96	-1.87	-10.25	-37.99
						NPV	-43.38

Source: AusNet analysis

7.4. Option 1: Augmentation in Cann River to extend the NLA31-CNR3 tie

The purpose of this option is to minimise the outage impact for the customers in the Cann River township and surrounding areas by introducing a backup supply via the NLA31 22kV feeder which currently ties with CNR3.

The option includes the installation of five ACRs and augmentation in Cann River to extend the NLA31-CNR3 tie to backup CNR1, CNR2 and CNR3. The feeder representation and proposed ACRs are shown in Figure 22.

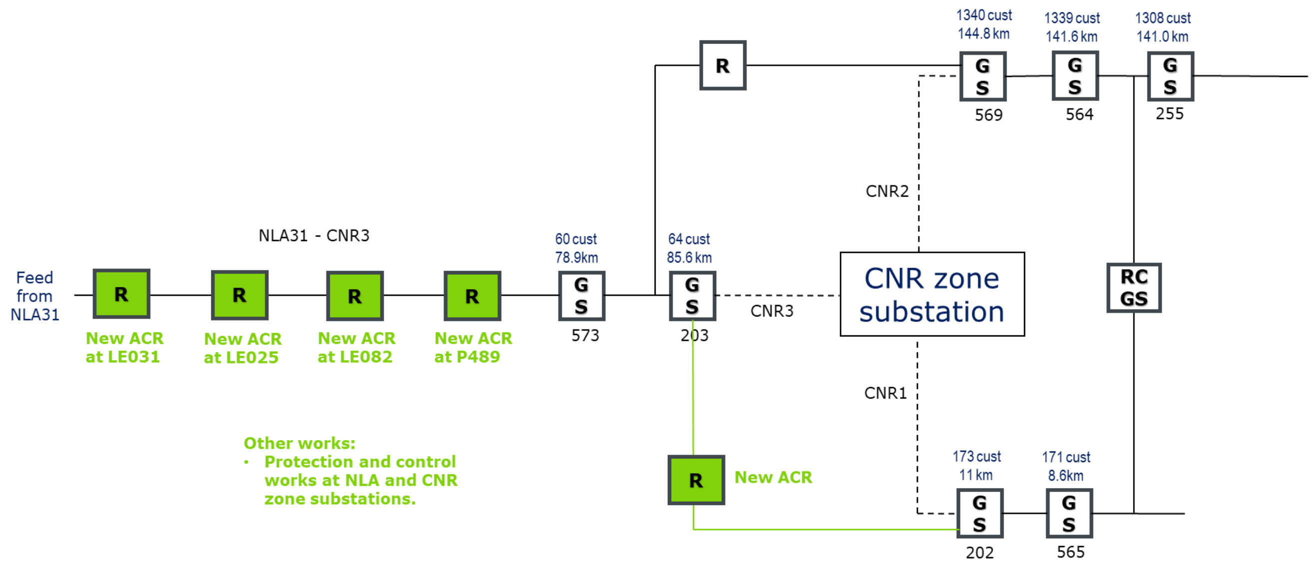


Figure 22: Representation of the CNR feeders including the proposed ACRs

7.4.1. Cost

7.4.1.1. Capex

AusNet used a detailed cost estimate unit for CNR1, 2, 3 Option 1. The scope of work includes:

- 22kV overhead line works
- 5 x new ACRs
- Protection and control works at NLA and CNR zone substations.

The capex estimate shown in Table 22. It is proposed that this project starts and finishes in FY27.

Table 22: CNR1, 2, 3 Option 1 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	2.52	-	-	-	-	2.52	2.52

Source: AusNet analysis

7.4.1.2. Opex

Additional operating expenditure associated with option 1 has been estimated at 0.5% of the capex cost per annum. The opex shown in Table 23 is relative to the Do nothing case. The FY29-FY31 opex values appear negative as the values are relative to the Do nothing case. The values reflect the reduction in reactive fault costs after the project is completed.

Table 23: CNR1, 2, 3 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	-	-	-0.05	-0.05	-0.04	-0.14	-0.72

Source: AusNet analysis

7.4.2. Benefits

Four hundred and fifty customers on CNR1, 2, 3 will benefit when there is an outage on the 66kV NLA-CNR line. The benefits have been estimated based on the historical outages.

We have assumed that NLA31 provides some backup capability to CNR3 presently and MAGS will already keep the CNR2 customers beyond gas switch 576 (refer to Figure 16). The benefits are shown in Table 24.

Table 24: CNR1, 2, 3 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	-	0.23	0.22	0.21	0.20	0.87	3.99

Source: AusNet analysis

7.4.3. Summary

Given the relatively low cost of this backup supply option, it provides a positive NPV for customers in Cann River and the surrounding regions as indicated in Table 25.

Table 25: CNR1, 2, 3 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	2.52	-	-0.05	-0.05	-0.04	2.38	1.80
Benefits	-	0.23	0.22	0.21	0.20	0.87	3.99
						NPV	**2.19**

Source: AusNet analysis

7.5. Option 2: New BESS for Cann River

Option 2 proposes a new Battery Energy Storage System (BESS) at Cann River to provide a backup supply for Cann River and the surrounding regions. The BESS size has been estimated as follows:

Average demand is assumed to be 318kW (386 customers with an average 0.82kW) per customer. The maximum average sustained outage times for CNR1, 2 and 3 due to 66kV line outages was approximately 20 hours.

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

- BESS 1 x 1.5MVA inverter (to allow for peak demand) and 1 x 6.50 MWh battery installation
- 2MVA step up transformer 415V/22kV
- 1 x ACR

7.5.1. Cost

7.5.1.1. Capex

We developed a capital cost estimate (shown in Table 26) for the proposed Cann River BESS using the following 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.
- Subcontractor indirect costs 10% of construction costs.
- Project management and construction management costs 8% of design and construction costs.
- Risk of 5% added to direct costs.
- 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 26: CNR1, 2, 3 Option 2 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	6.61	-	-	-	-	6.61	8.74

Source: AusNet analysis

7.5.1.2. Opex

O&M costs associated with the BESS are assumed as $150K per annum as indicated in Table 27.

Table 27: CNR1, 2, 3 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	-	0.05	0.05	0.05	0.04	0.19	0.77

Source: AusNet analysis

7.5.2. Benefits

The BESS will benefit the same 450 customers as option 1, however it will provide a higher benefit, provided the BESS is operated and maintained correctly. This is due to the source of energy (the BESS) being located at Cann River for option 2. In option 1, the source of energy is the NLA31 line which is exposed to faults. This means that the BESS can provide a supply in the cases were the upstream BDL 66kV (before the NLA 66kV line) experiences a fault, unlike in option 1. The benefits are shown in Table 28.

Table 28: CNR1, 2, 3 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	0.25	0.62	0.59	0.57	0.54	2.58	10.64

Source: AusNet analysis

7.5.3. Summary

The high benefits stream of the BESS option produces a positive NPV as indicated in Table 29.

Table 29: CNR1, 2, 3 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	6.61	0.05	0.05	0.05	0.04	6.80	9.52
Benefits	0.25	0.62	0.59	0.57	0.54	2.58	10.64
						NPV	**1.12**

Source: AusNet analysis

7.6. Preferred option (and sensitivity testing)

Option 1 provides an optimal solution by providing a relatively low cost back up to Cann River and surrounding areas. The sensitivity on this option is also favourable in all cases as indicated in Table 30.

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

	Central assumptions	Higher WACC	10% increase in capex	Comments
Do nothing	-	-	-	
Option 1 – Augmentation in Cann River to extend the NLA31-CNR3 tie	2.19	1.50	1.92	This is the preferred option under all scenarios
Option 2 – New BESS for Cann River	1.12	0.23	0.31	

Source: AusNet analysis

8. KLK11

8.1. Identified need

Customers on the Kinglake feeder number 11 (KLK11), 57kms north-east of Melbourne CBD, experience an average outage duration of 12.2 hours per annum. This is more than four times the outage impact experienced by the average AusNet customer.

The KLK11 feeder runs through heavily vegetated terrain (as shown in Figure 24). The KLK11 feeder has a spur that runs up towards Glenburn as shown in Figure 23 and there is an existing tie to the WYK24 HV feeder on Myers Creek Rd (as shown in Figure 24).

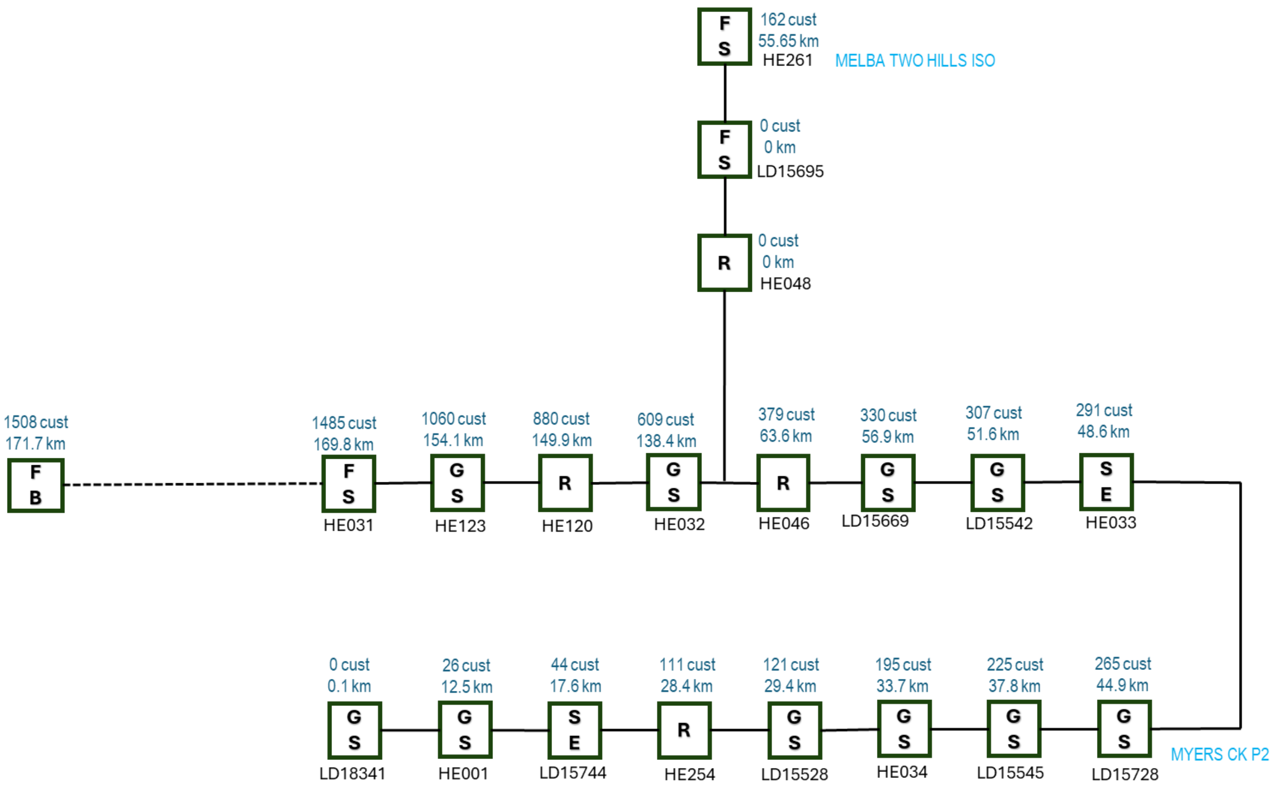


Figure 23: Representation of the KLK11 high voltage feeder (Present state).

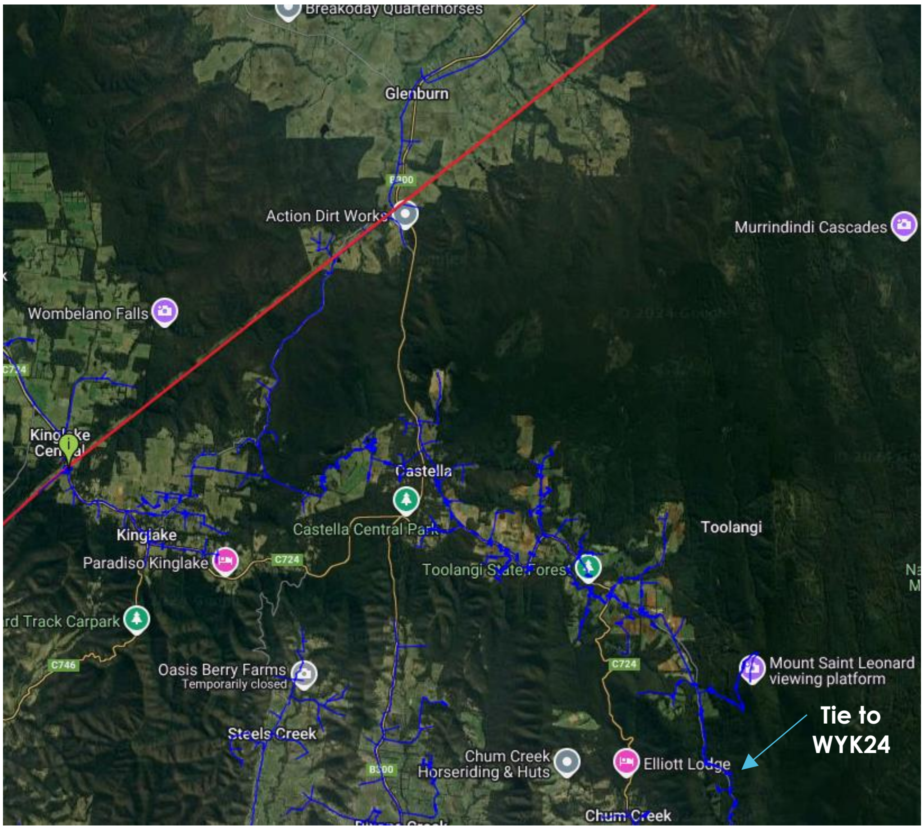


Figure 24: Map view of the KLK11 feeder showing the vegetation and terrain

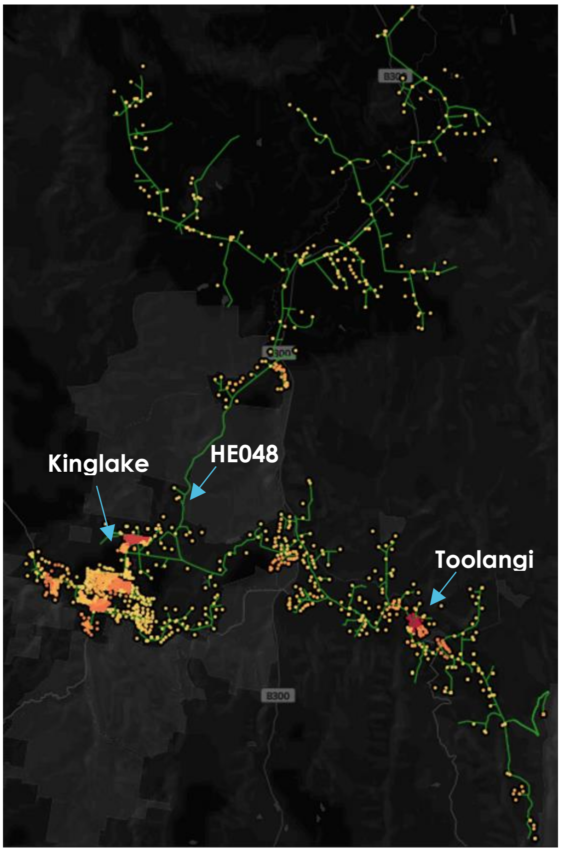


Figure 25: Customer outage heat map for KLK11

8.2. Options assessed

The majority of the customer outage impact is in the Kinglake township with some impact in the Toolangi area (as shown in Figure 25). There is also a large CMOS impact on the HE048 radial spur. Noting these characteristics, AusNet considered the following credible options:

- Option 1: Additional supply to the end of the Kinglake township and feeder tie (from HE048) to an MDI feeder.
- Option 2: Additional supply to the end of the Kinglake township and remote controlled gas switches on the north leg (HE048) of KLK11.

Other options considered but discounted include:

- Converting targeted sections of overhead line to underground through heavily vegetated areas: This option was discounted as the KLK11 feeder is at its REFCL capacitive current limit. Additional underground cable will introduce capacitive current to the feeder, meaning that the REFCL will not be able to perform to the mandatory performance requirements.
- Microgrids for Kinglake and Toolangi: The high cost of a microgrid for this demand, the replacement cost in years 15-20 and O&M costs make the microgrid non prudent over the longer term.

8.3. Do nothing

Customers on KLK11 will continue to experience approximately $400K of economic impacts per annum under a do nothing scenario. The costs in Table 31 also include the operational costs of outages at the same level as the past five years.

Table 31: KLK11 Do nothing scenario ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	0.21	0.20	0.19	0.18	0.17	0.93	3.15
Energy at risk	-0.41	-0.39	-0.37	-0.36	-0.34	-1.87	-6.92
						NPV	**-10.07**

Source: AusNet analysis

8.4. Option 1: Additional supply to the end of the Kinglake township and Feeder tie to an MDI feeder

Option 1 includes a new feeder to extend to the other end of the Kinglake township to provide a backup supply for Kinglake and a new feeder tie to the MDI1 feeder to provide a backup supply for the customers on the northern leg of KLK11. The location is shown in Figure 26 and an estimate of the length of the feeder tie (via roadways) is shown in Figure 27. A representation of the improvements is shown in Figure 28.

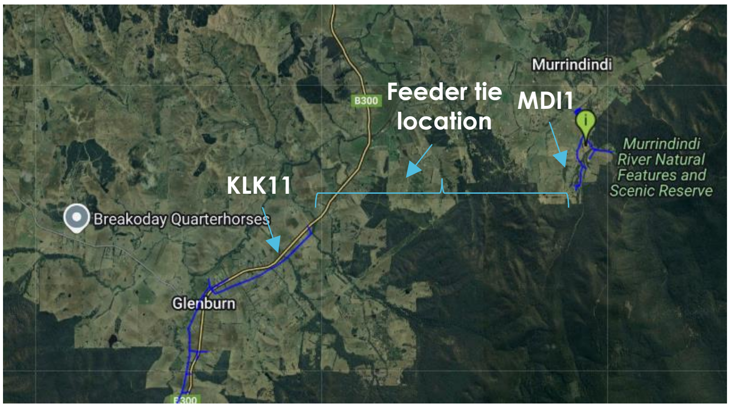


Figure 26: Potential feeder tie location for KLK11 to MDI1

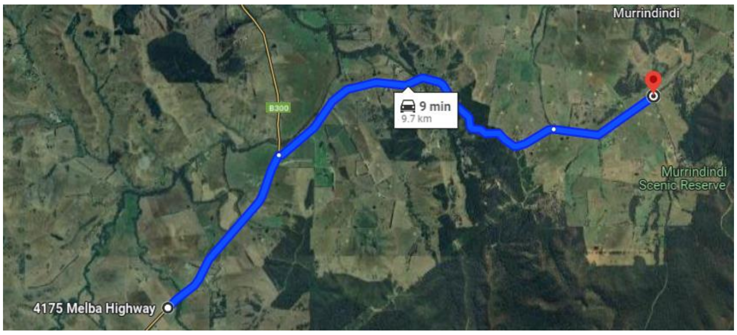


Figure 27: Estimate of the length for the KLK11 to MDI1 feeder tie

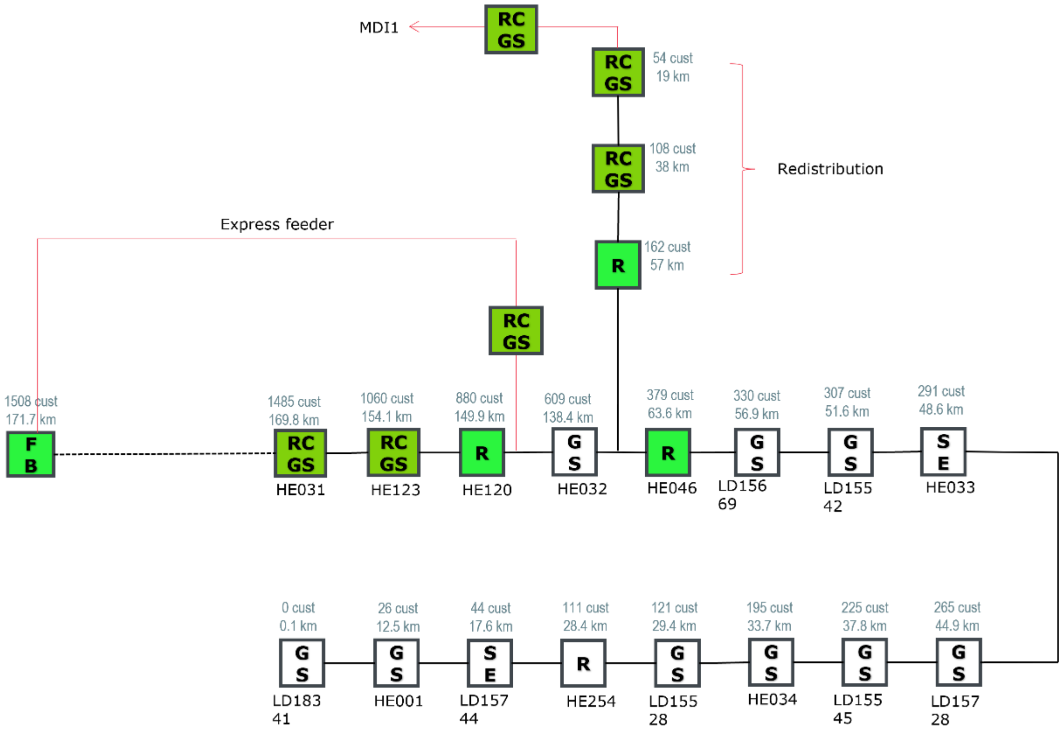


Figure 28: KLK11 option 1 feeder improvements

8.4.1. Cost

8.4.1.1. Capex

Unit costs were used to develop the capital expenditure estimate for KLK11 option 1. The scope of work includes:

- 3kms of overhead line for the new feeder to extend to the other end of Kinglake at [CIC] per km.
- 10kms of overhead line for the new KLK11 to MDI1 feeder tie. Assume 5kms at covered conductor rate of [CIC] per km and 5km at [CIC] per km.

- A [CIC] allowance for circuit breaker protection.
- 6 x remote controlled gas switches (to enable sectionalisation with the new feeder and feeder tie) at [CIC] per unit.
- 6 x REFCL remote fault indicators as KLK11 is a REFCL feeder, at [CIC] per unit.

The capex estimate is shown in Table 32. It is proposed that this project starts in FY27 and finishes in FY28.

Table 32: KLK11 option 1 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	2.88	4.60	-	-	-	7.48	7.48

Source: AusNet analysis

8.4.1.2. Opex

Additional operating expenditure associated with option 1 has been estimated at 0.5% of the capex cost per annum. The opex shown in Table 33 is relative to the Do nothing case. The FY29-FY31 opex values appear negative as the values are relative to the Do nothing case. The values reflect the reduction in reactive fault costs after the project is completed.

Table 33: KLK11 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	-	-	-0.07	-0.07	-0.06	-0.20	-1.02

Source: AusNet analysis

8.4.2. Benefits

The benefits associated with the feeder tie were calculated by reviewing the historical fault data for the H048 leg on the KLK11 feeder.

We assumed that the new KLK11 H048 (with 162 customers) can be split into three sections using remote controlled gas switches. The feeder tie means that there are two sources of supply for the three sections. Using remote control, the impacts of sustained faults can be limited to each section. This means that a fault in any of the new three sections will only impact the customers in that section.

We also calculated the benefits for the new Kinglake township feeder by reviewing the historical fault data for the section between the feeder circuit breaker and the HE120 ACR. It was assumed that this section can be split into three sections. Similar to the feeder tie, using remote control, the impacts of sustained faults can be limited to each section. This means that a fault in any of the new three sections (between the CB and HE120) will only impact the customers in that section. The benefits are shown in Table 34.

Table 34: KLK11 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	-	-	0.15	0.14	0.14	0.43	2.44

Source: AusNet analysis

8.4.3. Summary

The high cost of providing a feeder tie means that this option is NPV negative as indicated in Table 35.

Table 35: KLK11 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	2.88	4.60	-0.07	-0.07	-0.06	7.28	6.46
Benefits	-	-	0.15	0.14	0.14	0.43	2.44
						NPV	-4.02

Source: AusNet analysis

8.5. Option 2: Additional supply to the end of the Kinglake township and remote controlled gas switches on the north leg of KLK11

Option 2 includes a new feeder to extend to the other end of the Kinglake township to provide a backup supply for Kinglake (same as option 1). The location is shown in Figure 29 and an estimate of the length of the feeder tie is shown in Figure 30. Instead of introducing a backup supply via MDI1, option 2 includes remote controlled gas switches on the HE048 leg of KLK11. A representation of the improvements is shown in Figure 31.

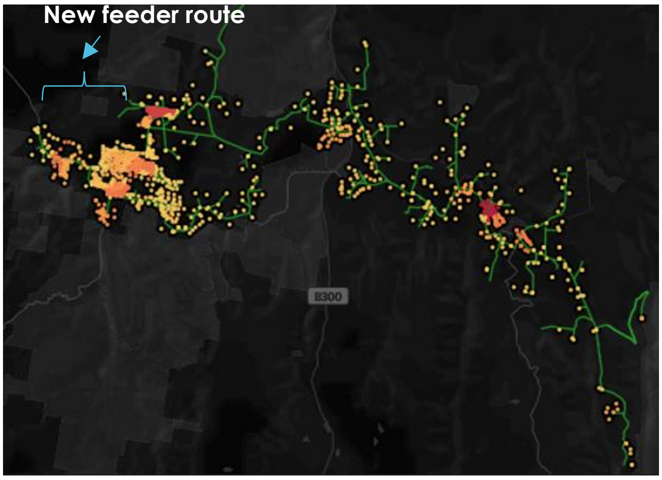


Figure 29: Location of the new KLK feeder, connecting to the other (electrical) end of the Kinglake township

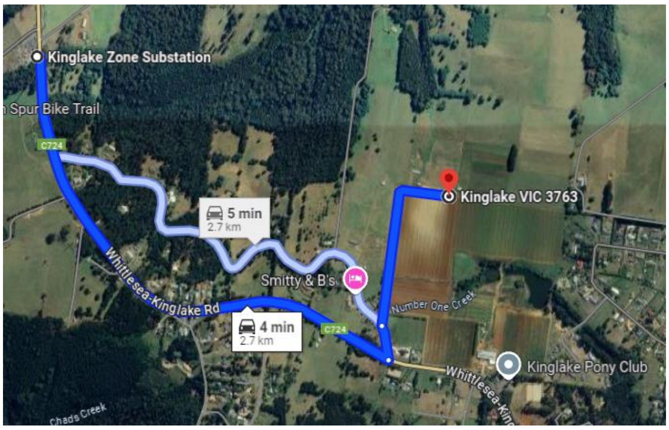


Figure 30: Estimate of the length for the new feeder to the other (electrical) end of the Kinglake township

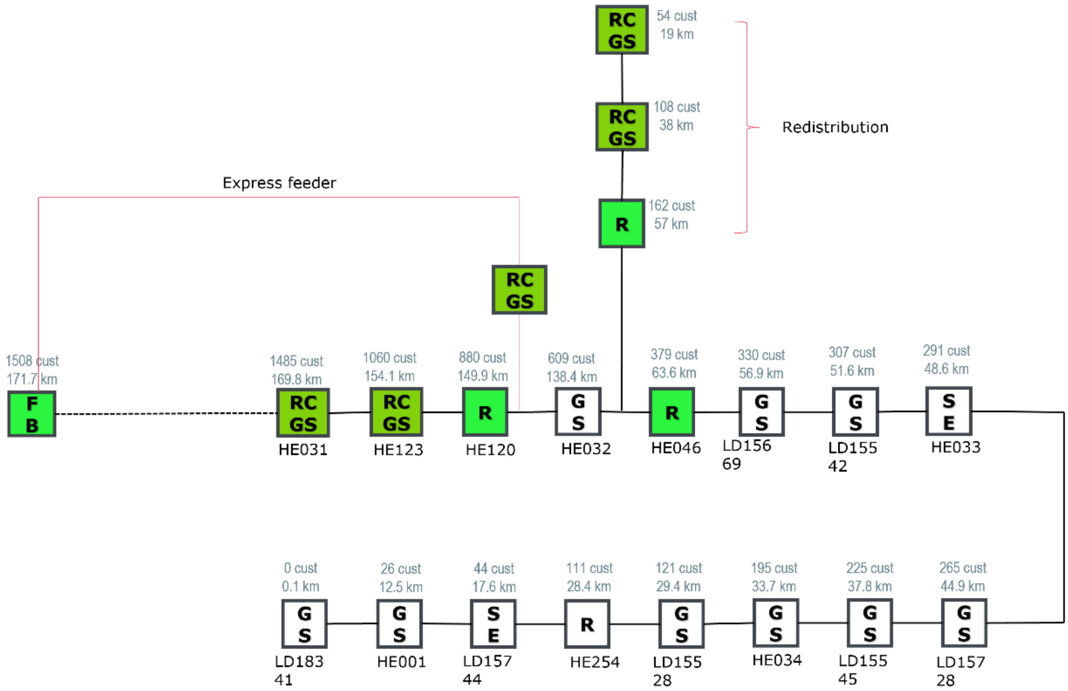


Figure 31: Solution option 2 for KLK11 feeder

8.5.1. Cost

8.5.1.1. Capex

Unit costs were used to develop the capital expenditure estimate for KLK11 option 2. The scope of work includes:

- 3kms of overhead line for the new feeder to extend to the other end of Kinglake at [CIC] per km.
- A [CIC] allowance for circuit breaker protection.
- 3 x remote controlled gas switches (to enable sectionalisation with the new feeder) at [CIC] per unit.
- 3 x REFCL remote fault indicators as KLK11 is a REFCL feeder, at [CIC] per unit.

The capex estimate shown in Table 36. It is proposed that this project starts and finishes in FY27.

Table 36: KLK11 option 2 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	1.98	-	-	-	-	1.98	1.98

Source: AusNet analysis

8.5.1.2. Opex

Additional operating expenditure associated with option 1 has been estimated at 0.5% of the capex cost per annum as shown in Table 37.

Table 37: KLK11 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	-	-0.09	-0.08	-0.08	-0.08	-0.33	-1.34

Source: AusNet analysis

8.5.2. Benefits

It was assumed that the new KLK11 H048 (with 162 customers) can be split into three sections using remote controlled gas switches. Using remote control, the impacts of sustained faults can be limited to each section. This means that a fault in any of the new three sections will only impact customers downstream of that device.

The benefits for the new Kinglake township feeder (and associated sectionalisation) were calculated by reviewing the historical fault data for the section between the feeder circuit breaker and the HE120 ACR. We assumed that this section can be split into three sections. Using remote control, the impacts of sustained faults can be limited to each section. This means that a fault in any of the new three sections (between the CB and HE120) will only impact the customers in that section.

The benefits for the new Kinglake township feeder were calculated using the same methodology as option 1. The benefits are shown in Table 38.

Table 38: KLK11 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	-	0.13	0.12	0.12	0.11	0.47	2.11

Source: AusNet analysis

8.5.3. Summary

The new short feeder and additional sectionalisation at the front end of the feeder and on the HE048 leg provides an optimal outcome for customers, with the NPV model indicating that this option is NPV positive as indicated in Table 39.

Table 39: KLK11 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	1.98	-0.09	-0.08	-0.08	-0.08	1.65	0.64
Benefits	-	0.13	0.12	0.12	0.11	0.47	2.11
						NPV	**1.47**

Source: AusNet analysis

8.6. Preferred option (and sensitivity testing)

Option 2 is the preferred option as it is NPV positive and provides and optimal solution for the heavily impacted customers in the Kinglake township and the radial northern leg of KLK11. The NPV sensitivity is shown in Table 40.

Table 40: Net Present Value ($m, 2023-24 dollars)

	Central assumptions	Higher WACC	10% increase in capex	Comments
Do nothing	-	-	-	
Option 1 – Additional supply to the end of the Kinglake township and Feeder tie to an MDI feeder	-4.02	-4.48	-4.99	
Option 2 – Additional supply to the end of the Kinglake township and remote controlled gas switches on the north leg of KLK11	1.47	0.98	1.37	This is the preferred option under all scenarios

Source: AusNet analysis

9. MDI1

9.1. Identified need

Customers on the Murrindindi MDI1 feeder, 100kms northeast of Melbourne, experience an average outage duration of 13.8 hours per annum. This is almost five times the outage impact experienced by the average AusNet customer.

MDI1 is supplied from the Murrindindi zone substation which has a single 66kV/22kV transformer with the one 22kV feeder, MDI1, supplied by an automatic circuit recloser. This single feeder supplies three phase 22kV to the region shown in Figure 33 and single wire earth return network to the area shown in Figure 32 (up to the Murrindindi airport). The Seymour SWER network from SMR14 extends close to the Murrindindi airport, however this circuit does not have the capacity to pick up supply and act as a backup.

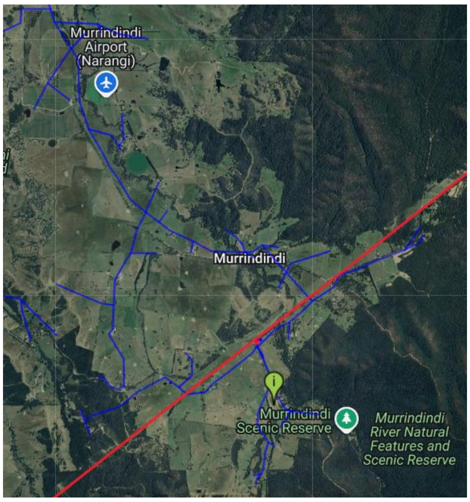


Figure 32: MDI1 supply area including the 22kV and SWER network

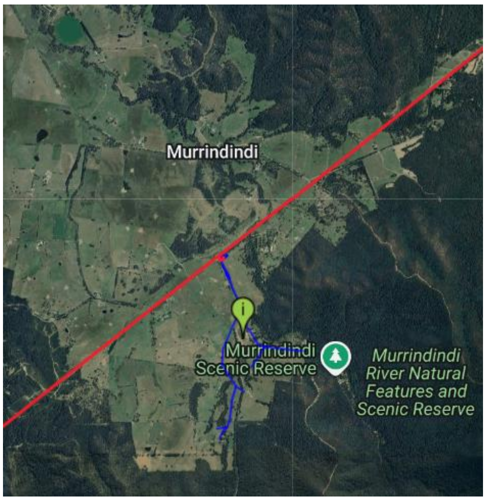


Figure 33: MDI1 three phase 22kV supply area

9.2. Options assessed

The historical outage data for MDI1 indicates that the majority of sustained faults impact all of the customers on MDI1 due to a trip of the MDI1ACR. Noting these characteristics, we determined that sectionalisation is an effective solution to minimise the number of customers impacted for each fault. Due to the small number of customers in this area, we also considered stand alone power systems. In summary, we considered:

- Option 1: Additional SWER ACRs
- Option 2: Stand alone power systems for customers

Other options considered but discounted include:

- Feeder ties have been excluded as the nearest three phase network is 10kms away. The KLK11 extension suggested in KLK11 option 1 may provide some benefit to the southern end of the MDI1 feeder. However it will not assist the other SWER sections of the MDI feeder.

9.3. Do nothing

Customers on MDI1 will continue to experience approximately $8K of economic impacts per annum under a do nothing scenario. The costs in Table 41 also includes the operational costs of outages at the same level as the past five years.

Table 41: MDI1 Do nothing scenario ($K, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	3.99	3.78	3.58	3.39	3.21	17.95	60.78
Energy at risk	-8.37	-8.01	-7.66	-7.33	-7.02	-38.39	-142.27
						NPV	**-203.05**

Source: AusNet analysis

Table 42: MDI1 Do nothing scenario ($K, discounted, 2023-24 dollars) (using AusNet QCV Residential VCR)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	3.99	3.78	3.58	3.39	3.21	17.95	60.78
Energy at risk	-10.69	-10.23	-9.78	-9.36	-8.96	-49.01	-181.62
						NPV	**-242.41**

Source: AusNet analysis

9.4. Option 1: SWER sectionalisation

Option 1 includes additional SWER ACRs to split the feeder into additional sections. The protection coordination will need to be reviewed in the design phase. If the coordination is difficult, the SWER ACRs can be set up as sectionalisers (or via remote control and automation) to achieve a similar reliability outcome.

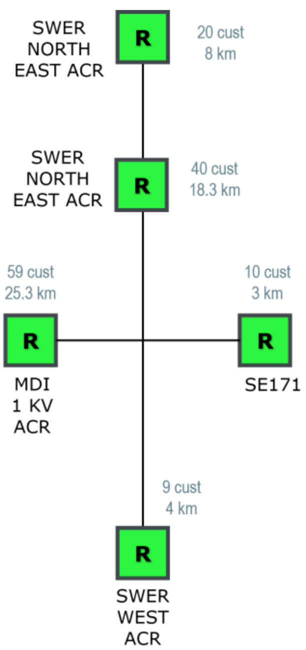


Figure 34: Solution option 2 for KLK11 feeder

9.4.1. Cost

9.4.1.1. Capex

Unit costs were used to develop the capital expenditure estimate for MDI1 option 1. The scope of work includes:

- 3 x SWER ACRs with remote control at [CIC] per unit.

The capex estimate shown in Table 43. It is proposed that this project starts and finishes in FY27.

Table 43: MDI1 Option 1 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	[CIC]	-	-	-	-	[CIC]	[CIC]

Source: AusNet analysis

9.4.1.2. Opex

Additional operating expenditure associated with option 1 has been estimated at 0.5% of the capex cost per annum. The opex shown in Table 44 is relative to the Do nothing case. The FY31 opex values appear negative as the values are relative to the Do nothing case. The values reflect the reduction in reactive fault costs after the project is completed.

Table 44: MDI1 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	-	-0.00	-0.00	-0.00	-0.00	-0.01	-0.03

Source: AusNet analysis

9.4.2. Benefits

The benefits were calculated by reviewing the historical fault data for the MDI1 feeder.

We assumed that the MDI1 feeder can be split into three sections by using the existing sectionaliser to supply the 22kV network to the south and three new ACRs to supply the SWER networks extending east and west and to split the longer northeast SWER network. The sectionalisation means that the impacts of sustained faults can be limited to each section. This means that a fault in any of the four sections will only impact the customers in that section. The benefits for MDI1 Option 1 are shown in Table 45. The benefits, using the AusNet QCV residential value, are also shown in Table 46.

Table 45: MDI1 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	0.00	0.01	0.00	0.00	0.00	0.02	0.09

Source: AusNet analysis

Table 46: MDI1 Option 1 Benefits (using AusNet QCV Residential VCR), relative to Do Nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Benefits	0.00	0.01	0.01	0.01	0.01	0.03	0.11

Source: AusNet analysis

9.4.3. Summary

This option is NPV negative, under both sensitivity cases as indicated in Table 47 and Table 48.

Table 47: MDI1 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	0.21	-0.00	-0.00	-0.00	-0.00	0.21	0.18
Benefits	0.00	0.01	0.00	0.00	0.00	0.02	0.09
						NPV	-0.09

Source: AusNet analysis

Table 48: MDI1 Option 1 Summary, relative to Do Nothing case (using AusNet QCV Residential VCR) ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	0.21	-0.00	-0.00	-0.00	-0.00	0.21	0.18
Benefits	0.00	0.01	0.01	0.01	0.01	0.03	0.11
						NPV	-0.07

Source: AusNet analysis

9.5. Option 2: Stand alone power systems

Option 2 proposes that all of the customers on MDI1 network are provided standalone power systems as backup systems when power outages occur.

9.5.1. Cost

9.5.1.1. Capex

Unit costs were used to develop the capital expenditure estimate for MDI1 option 2. The scope of work includes:

- 59 x SAPS at $40K per unit[17].

The capex estimate shown in Table 49. It is proposed that this project starts in FY27 and finishes in FY28.

Table 49: MDI1 Option 2 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	1.18	1.12	-	-	-	2.30	2.30

Source: AusNet analysis

[17] Source: https://offgridaustralia.com.au/faq/how-much-does-an-off-grid-system-cost/

9.5.1.2. Opex

Additional operating expenditure associated with option 2 has been estimated at $1K per SAPS per annum as shown in Table 50. This cost is to cover inspections, servicing and fuel delivery.

Table 50: MDI1 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	-	-	0.01	0.01	0.01	0.02	0.10

Source: AusNet analysis

9.5.2. Benefits

If correctly maintained and operated, a SAPS approach will remove all of the outage costs for customers. The benefits are shown in Table 51. The benefits, using the AusNet QCV residential value, are also shown in Table 52.

Table 51: MDI1 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	-	-	0.01	0.01	0.01	0.02	0.13

Source: AusNet analysis

Table 52: MDI1 Option 2 Benefits (using AusNet QCV Residential VCR), relative to Do Nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Benefits	-	-	0.01	0.01	0.01	0.03	0.16

Source: AusNet analysis

9.5.3. Summary

The high cost of providing SAPS means that this option is NPV negative in both scenarios shown in Table 53 and Table 54. This option will also have a more unfavourable NPV in the long term if we consider replacement of the SAPS systems in 15-20 years, along with replacement parts in the 1 to 15 year period.

Table 53: MDI1 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	1.18	1.12	0.01	0.01	0.01	2.32	2.40
Benefits	-	-	0.01	0.01	0.01	0.02	0.13
						NPV	**-2.28**

Source: AusNet analysis

Table 54: MDI1 Option 1 Summary, relative to Do Nothing case (using AusNet QCV Residential VCR) ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	1.18	1.12	0.01	0.01	0.01	2.32	2.40
Benefits	-	-	0.01	0.01	0.01	0.03	0.16
						NPV	**-2.24**

Source: AusNet analysis

9.6. Preferred option (and sensitivity testing)

Option 1 provides an optimal solution by sectionalising the MDI1 feeder using SWER ACRs and a remote controlled gas switch device. The NPV is negative in all cases as shown in Table 55, however we propose that option 1 proceeds as it is low cost and it will benefit MDI1 customers. These are customers that experience almost five times the outage impact experienced by the average AusNet customer.

Table 55: Net Present Value ($m, 2023-24 dollars)

	Central assumptions	Higher WACC	10% increase in capex	Comments
Do nothing	-	-	-	
Option 1 – SWER sectionalisation	-0.09	-0.11	-0.12	This is the preferred option under all scenarios
Option 2 – Stand alone power systems	-2.28	-2.26	-2.64	

Source: AusNet analysis

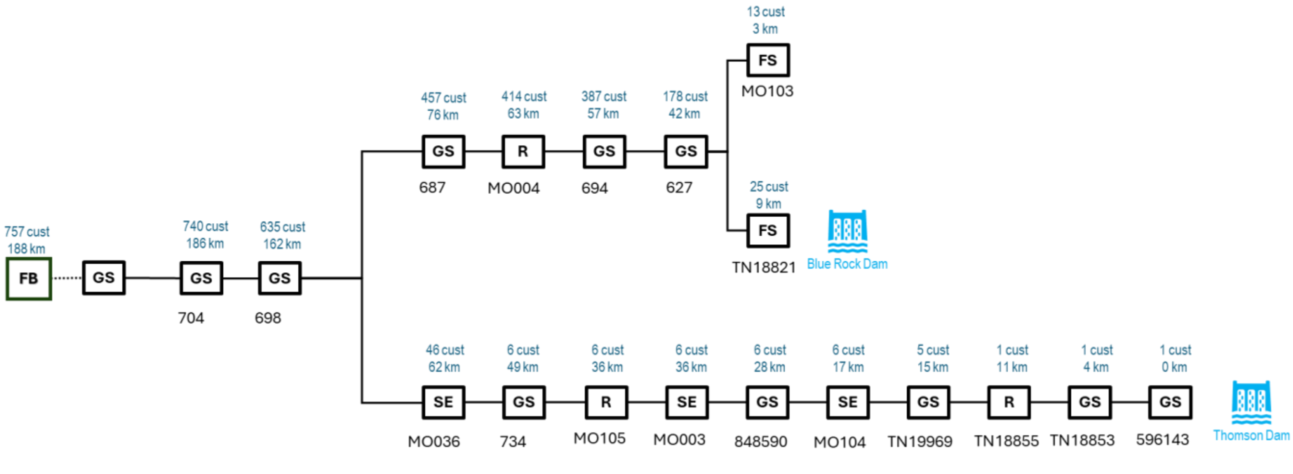
10. MOE13

10.1. Identified need

Customers on the Moe feeder number 13 (MOE13), in the Gippsland area of Victoria, experience an average outage duration of 16.4 hours per annum. This is more than five times the outage impact experienced by the average AusNet customer.

Moe feeder number 13 (MOE13) supplies the township of Willow Grove and surrounding areas of Hill End, Fumina South, Westbury, Thalloo and the Thomson Dam as shown in Figure 35. In total, MOE13 supplies 728 customers and has a total length of 188 kms as shown in Figure 36.

Figure 35: MOE13 supply area.



Legend: FB: Feeder Head Circuit Breaker, FS: Fused Switch, GS: Gas Switch, R: Automatic Circuit Recloser, SE: Sectionaliser.

Figure 36: Representation of the MOE13 high voltage feeder (Present state)

Most customer outages occur downstream of the MOE13 feeder circuit breaker and the MO004 and MO015 automatic circuit reclosers and the key fault causes are vegetation issues, extreme weather and lightning.

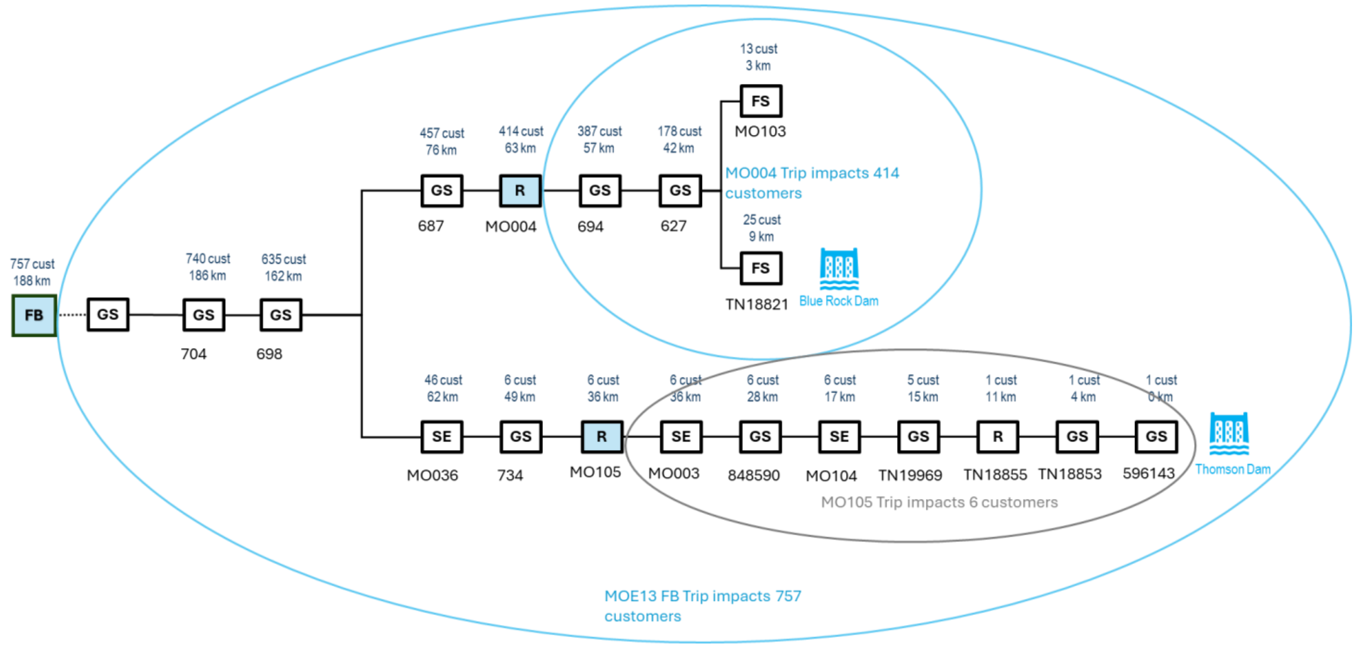


Figure 37: Representation of the MOE13 high voltage feeder showing the impact in the key switch zones MO13 Feeder CB, MO004, MO105.

The schematic representation of MOE013 in Figure 37 indicates that a reduction in customers impacted per fault could be achieved by adding further sections:

- between the MOE013 CB, MO004 and MO105, and
- beyond MOE004.

The section beyond MO105 will not benefit from additional sectionalisation, however AusNet will continue to explore asset management mitigation options to improve performance for the six customers beyond switch MO015.

10.2. Options assessed

Considering the schematic layout of MOE13, AusNet determined that additional switching devices and automation is the most credible option. AusNet considered:

- Option 1: Two new ACRs and two new remote controlled gas switches.
- Option 2: Five new ACRs and ten new remote controlled gas switches.
- Option 3: New feeder tie to MOE21.

Other options considered but discounted include:

- Undergrounding: This option was discounted due to the high cost.

10.3. Do nothing

Customers on MOE13 will continue to experience an average of $1m of economic impacts per annum under a do nothing scenario, as shown in Table 56. The costs in Table 56 also includes the operational costs of outages at the same level as the past five years.

Table 56: MOE13 Do Nothing Option ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	0.13	0.12	0.12	0.11	0.10	0.58	1.97
Energy at risk	-1.02	-0.97	-0.93	-0.89	-0.85	-4.66	-17.26
						NPV	-19.24

Source: AusNet analysis

10.4. Option 1: Two new ACRs and two new remote controlled gas switches

The network topology was reviewed to determine locations for new switch automation sections. The proposed new devices and associated customer benefit zones are shown in green in Figure 38.

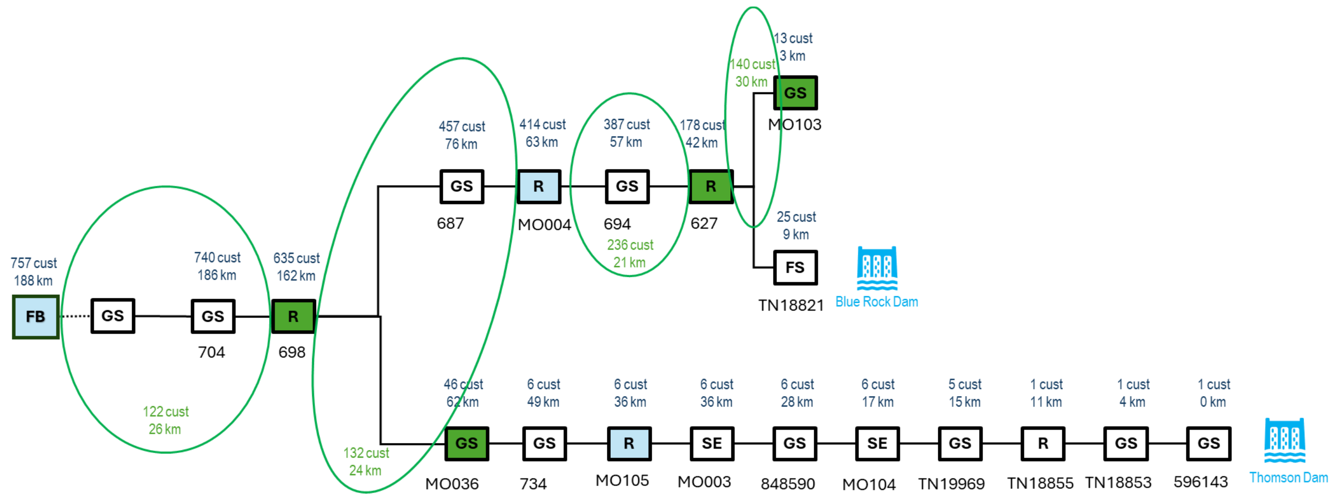


Figure 38: Proposed reclosers and remote controlled gas switches (shown in green) on MOE13 and customer benefit zones (circled in green).

10.4.1. Cost

10.4.1.1. Capex

Unit costs were used to develop the capital expenditure estimate for MOE13 option 1. The scope of work includes:

- two new ACRs at [CIC] per unit.
- two new remote controlled gas switches (including remote fault indicators) at [CIC] per unit.

The capex estimate shown in Table 57. It is proposed that this project starts in FY27 and finishes in FY28.

Table 57: MOE13 Option 1 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	0.17	0.16	-	-	-	0.34	0.34

Source: AusNet analysis

10.4.1.2. Opex

Additional operating expenditure associated with option 1 has been estimated at 0.5% of the capex cost per annum. The opex shown in Table 58 is relative to the Do nothing case. The FY29-FY31 opex values appear negative as the values are relative to the Do nothing case. The values reflect the reduction in reactive fault costs after the project is completed.

Table 58: MOE13 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	-	-	-0.06	-0.05	-0.05	-0.16	-0.84

Source: AusNet analysis

10.4.2. Benefits

Benefits for option 1 are assessed using the present customer minutes off supply in the switch zone associated with the MOE13 feeder circuit breaker and the switch zone associated with the MO004 device. The benefits are shown in Table 59.

Table 59: MOE13 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	-	-	0.22	0.21	0.20	0.64	3.67

Source: AusNet analysis

10.4.3. Summary

The option 1 for MOE13 which includes two new ACRs and two new remote controlled gas switches is NPV positive, as shown in Table 60.

Table 60: MOE13 Option 1 Cost-Benefit Summary, relative to Do Nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	0.17	0.16	-0.06	-0.05	-0.05	0.17	-0.51
Benefits	-	-	0.22	0.21	0.20	0.64	3.67
						NPV	**4.18**

Source: AusNet analysis

10.5. Option 2: Five new ACRs and ten new remote controlled gas switches

Similar to option 1, it is proposed to install new ACRs and remote controlled gas switches to increase the sectionalisation capability of the MOE13 feeder.

10.5.1. Cost

10.5.1.1. Capex

Unit costs were used to develop the capital expenditure estimate for MOE13 option 2. The scope of work includes:

- Five new ACRs at [CIC] per unit.
- Ten new remote controlled gas switches (including remote fault indicators) at [CIC] per unit.

The capex estimate is shown in Table 61. It is proposed that this project starts in FY27 and finishes in FY28.

Table 61: MOE13 Option 2 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	0.59	0.56	-	-	-	1.16	1.16

Source: AusNet analysis

10.5.1.2. Opex

Additional operating expenditure associated with option 1 has been estimated at 0.5% of the capex cost per annum as shown in Table 62.

Table 62: MOE13 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	-	-	-0.06	-0.05	-0.05	-0.16	-0.85

Source: AusNet analysis

10.5.2. Benefits

Benefits for option 2 were calculated using the method described in section 10.4.2. The additional ACRs and remote controlled gas switches provide better sectionalisation, meaning that the benefit is higher than option 1. However, this improved benefit is marginal – only 5% greater than in option 1. A summary is shown in Table 63.

Table 63: MOE13 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	-	-	0.27	0.26	0.25	0.78	4.43

Source: AusNet analysis

10.5.3. Summary

Option 2 for MOE13, which includes five new ACRs and ten new remote controlled gas switches is NPV positive, as shown in Table 64.

Table 64: MOE13 Option 2 Cost-Benefit Summary, relative to Do Nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	0.59	0.56	-0.06	-0.05	-0.05	0.99	0.31
Benefits	-	-	0.27	0.26	0.25	0.78	4.43
						NPV	**4.12**

Source: AusNet analysis

10.6. Option 3: New feeder tie to MOE21

This option considers the option of creating a second source of supply for MOE13 part way along the feeder so that sectionalisation and an alternative supply can be provided if faults occur between the Willow Grove area and the MOE13 feeder circuit breaker. It is proposed that the new feeder tie is complemented by additional ACRs and remote controlled gas switches to enable sectionalisation. The MOE21 feeder tie is shown in Figure 39 and Figure 40.

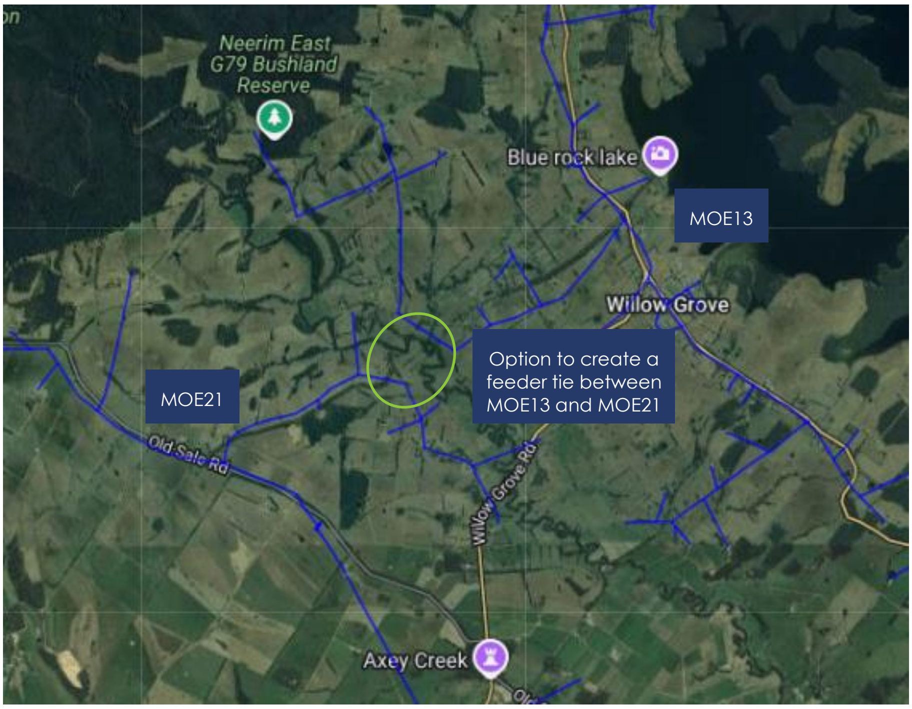


Figure 39: Map showing the potential feeder tie location between MOE13 and MOE21.

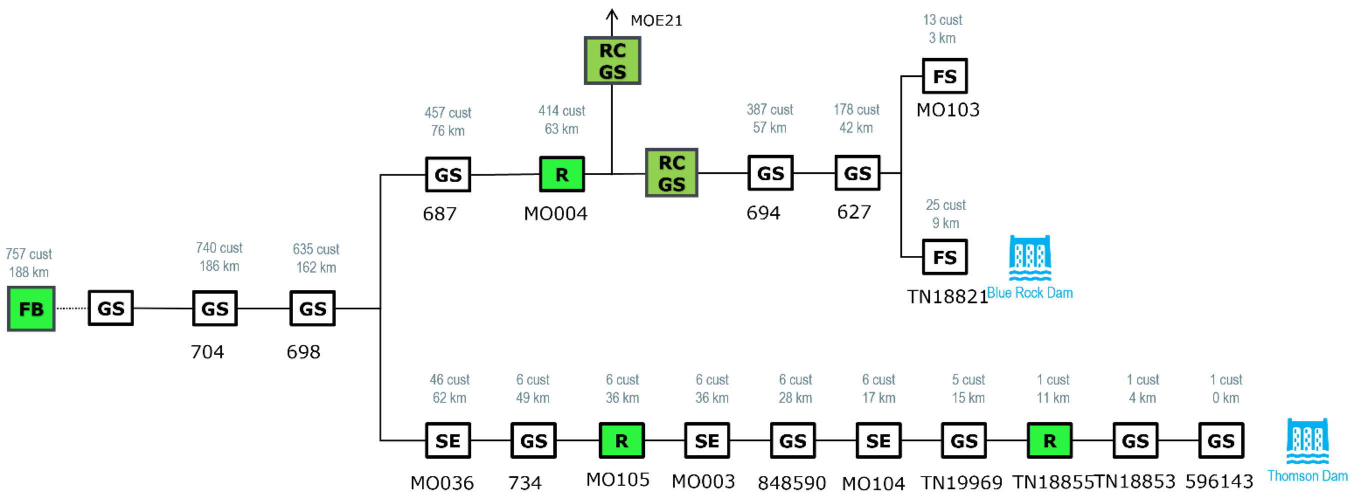


Figure 40: Feeder tie to MOE21

10.6.1. Cost

10.6.1.1. Capex

Unit costs were used to develop the capital expenditure estimate for MOE13 option 3. The scope of work includes:

- 5 km of 22kV overhead line between MOE13 and MOE21 estimated at [CIC] per km.
- Two new remote controlled gas switches (including remote fault indicators) at [CIC] per unit.

The capex estimate shown in Table 65. It is proposed that this project starts and finishes in FY27.

Table 65: MOE13 Option 3 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	2.34	-	-	-	-	2.34	2.34

Source: AusNet analysis

10.6.1.2. Opex

Additional operating expenditure associated with option 1 has been estimated at 0.5% of the capex cost per annum as shown in Table 66.

Table 66: MOE13 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	-	-0.06	-0.05	-0.05	-0.05	-0.21	-0.87

Source: AusNet analysis

10.6.2. Benefits

Benefits for option 3 were calculated by determine the CMOS saved due to faults that trip the feeder breaker (according to the historical fault rates for that breaker) for the benefitting 414 customers (downstream of MO004) which can be supplied by MOE21. The low probability of MOE21feeder and the MOE13 experiencing a fault at the same time has been estimated and removed from the CMOS benefit.

It has also been assumed that while the MOE21 feeder tie-in point has capacity to supply the average demand of the 414 customers, the maximum demand experienced may be greater. Therefore, it has been assumed that the MOE21 feeder tie will only be able to operate 85% of the year.

A summary of the benefits is shown in Table 67.

Table 67: MOE13 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	-	0.32	0.31	0.29	0.28	1.20	5.35

Source: AusNet analysis

10.6.3. Summary

Option 3 for MOE13, which includes a feeder tie and two new remote controlled gas switches is NPV positive, as shown in Table 68.

Table 68: MOE13 Option 3 Cost-Benefit Summary, relative to Do Nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	2.34	-0.06	-0.05	-0.05	-0.05	2.13	1.47
Benefits	-	0.32	0.31	0.29	0.28	1.20	5.35
						NPV	3.87

Source: AusNet analysis

10.7. Preferred option (and sensitivity testing)

Option 3 is recommended as it provides the best benefit to customers on MOE13 and it is still NPV positive under all scenarios as shown in Table 69.

Table 69: Net Present Value ($m, 2023-24 dollars)

	Central assumptions	Higher WACC	10% increase in capex	Comments
Do nothing	-	-	-	
Option 1 – Two new ACRs and two new remote controlled gas switches	4.18	3.49	4.26	
Option 2 – Five new ACRs and ten new remote controlled gas switches	4.12	3.33	4.08	
Option 3 – New feeder tie to MOE21	3.87	2.98	3.65	This is the preferred option

Source: AusNet analysis

11. MSD1

11.1. Identified need

Customers on the Mansfield feeder number 1 (MSD1), in the Hume area of Victoria, experience an average outage duration of 12.7 hours per annum. This is more than four times the outage impact experienced by the average AusNet customer.

The MSD1 feeder runs through heavily vegetated terrain (as shown in Figure 43) and 84% of the customer minutes of supply occur beyond the MS005 ACR which is shown in the feeder representation in Figure 41 and the outage heat map in Figure 42.

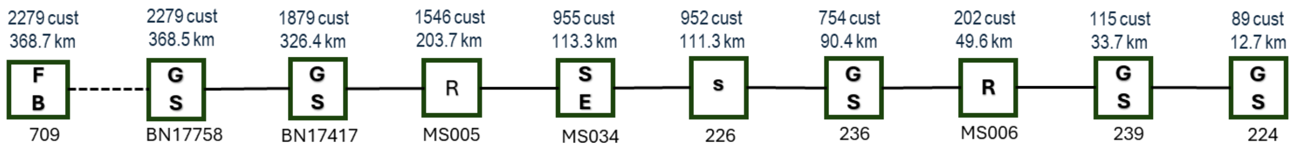


Figure 41: Representation of the MSD1 high voltage feeder (Present state).

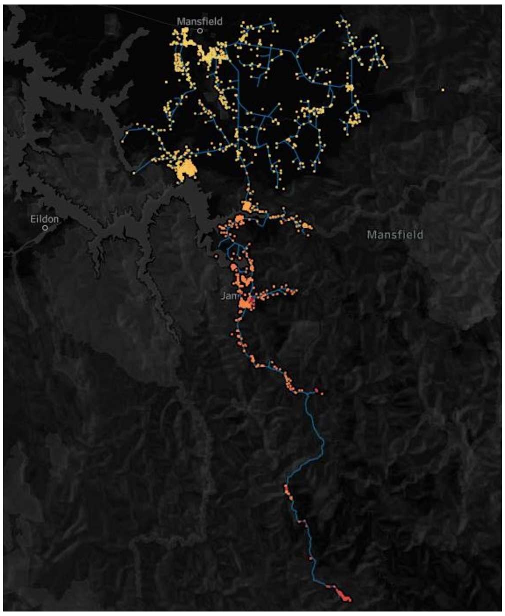


Figure 42: Customer outage heat map for the MSD1 feeder.

11.2. Options assessed

The majority of faults occur beyond MS005 on the southern section of MSD1 and the sections beyond MS005 run through heavily vegetated terrain. Noting these characteristics, it was determined that undergrounding should be considered as a credible option. Given that underground cable can present future issues with REFCL compliance, targeted express overhead sections were also considered.

In summary, the following options were considered:

- Option 1: 10kms of targeted undergrounding between Howqua Inlet and Kevington.
- Option 2: 10kms of targeted express overhead sections between Howqua Inlet and Kevington.

Other options considered but discounted include:

- Feeder ties: This option was discounted due to the large distance to other feeders and the challenging terrain, which would result in a very high cost for a feeder tie versus the benefits. Refer to the 51km distance in Figure 44.
- 40kms of targeted undergrounding. This option has been discounted as the large amount of capacitance introduced by the cable makes the REFCL non-compliant.
- Microgrid at Jamieson (Beyond MS034). Refer to BN11 business case. The replacement cost and O&M costs make the microgrid non prudent over the longer term.

Figure 43: Map view of the MSD1 feeder

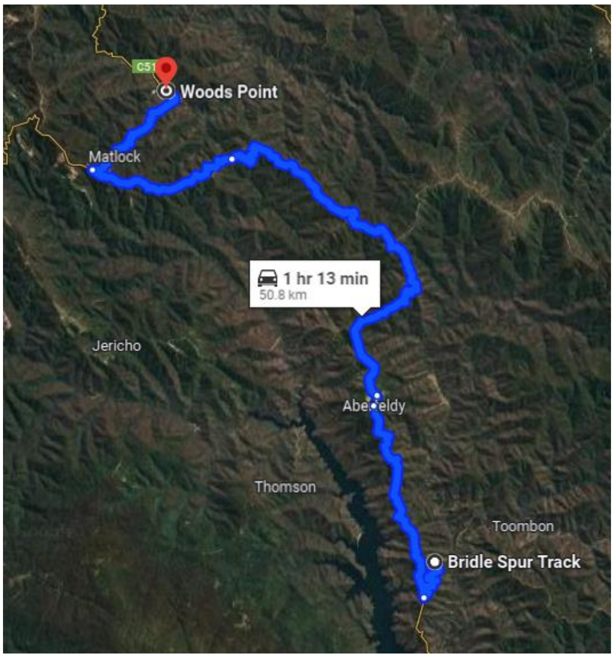


Figure 44: 51kms between MSD1 and MOE13 across difficult terrain.

11.3. Do nothing

Customers on MSD1 will continue to experience approximately $700K of economic impacts per annum under a do nothing scenario. The costs in Table 70 also includes the operational costs of outages at the same level as the past five years.

Table 70: MSD1 Do nothing summary ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	0.24	0.23	0.21	0.20	0.19	1.07	3.63
Energy at risk	-0.68	-0.65	-0.62	-0.59	-0.57	-3.10	-11.48
						NPV	**-15.12**

Source: AusNet analysis

11.4. Option 1: 10 kms of targeted undergrounding of MSD1

Option 1 includes targeted undergrounding from ACR MS034 onwards, with particular targeting of the section between Howqua Inlet and Kevington, which is a key customer outage area as shown in the outage heat map in Figure 42.

11.4.1. Cost

11.4.1.1. Capex

Unit costs were used to develop the capital expenditure estimate for MSD1 option 1. The scope of work includes:

- 10kms of underground cable at [CIC] per km.

The capex estimate shown in Table 71. It is proposed that this project starts and finishes in FY27.

Table 71: MSD1 Option 1 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	[CIC]	-	-	-	-	[CIC]	[CIC]

Source: AusNet analysis

11.4.1.2. Opex

Additional operating expenditure associated with option 1 has been estimated at 0.5% of the capex cost per annum. The opex shown in Table 72 is relative to the Do nothing case. The FY28-FY31 opex values appear negative as the values are relative to the Do nothing case. The values reflect the reduction in reactive fault costs after the project is completed.

Table 72: MSD1 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	-	-0.02	-0.02	-0.01	-0.01	-0.06	-0.24

Source: AusNet analysis

11.4.2. Benefits

A review of the fault causes indicates that the majority of faults are caused by lightning, animals and vegetation. All of these fault causes will be removed via the installation of underground cable.

The outage impact map in Figure 42 indicates that the section between Howqua Inlet and Kevington is a high impact area.

The majority, 85%, of customers on the MS005 section are connected before the end of the Jamieson township. This means that targeted undergrounding in the 20kms section between Howqua Inlet and the end Jamieson will have a large impact on CMOS.

If the new 10km of underground sections can be targeted to replace the overhead feeder backbone in this 20km section, then the likelihood of an outage will greatly reduce. This region corresponds to the feeder backbone between gas switch 236 and gas switch 239. The benefits have been calculated based on the historical outage data and the benefits of targeted undergrounding to customers on MSD1 in this region. The benefits are shown in Table 73. It has been assumed that 85% of faults resulting in the tripping of MS034 and MS006 reclosers occur in this 20km high impact area. Therefore, undergrounding 10km of this 20km feeder backbone section will half the average outage duration experienced by the 955 customers downstream of MS034 each year.

Table 73: MSD1 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	0.25	0.24	0.23	0.23	0.22	1.15	4.25

Source: AusNet analysis

11.4.3. Summary

The high cost of converting this length of circuit to underground means that this option is NPV negative. This option is only technically feasibility in the short term based on the REFCL capacitive current forecasts. The introduction of 10kms of underground cable (and its capacitive current) will mean that the REFCL will become non-compliant in the next five years based on the forecasts. The summary is shown in Table 74.

Table 74: MSD1 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	8.01	-0.02	-0.02	-0.01	-0.01	7.95	7.77
Benefits	0.25	0.24	0.23	0.22	0.21	1.15	4.25
						NPV	**-3.52**

Source: AusNet analysis

11.5. Option 2: 10kms of targeted express overhead sections between Howqua Inlet and Kevington

Option 2 takes a similar approach to option 1 in targeting the Howqua Inlet to Kevington area, however in option 2 an overhead express feeder section is proposed as a lower cost solution compared to undergrounding. Due to the limited space and difficult terrain surrounding the existing MSD1 feeder backbone in this region, a small portion of the 10km express feeder (assumed 4km) will need to be undergrounded.

11.5.1. Cost

11.5.1.1. Capex

Unit costs were used to develop the capital expenditure estimate for MSD1 option 2. The scope of work includes:

- 6kms of overhead line at [CIC] per km.
- 4kms of underground line at [CIC] per km.
- 7km of easement allowance at [CIC] per km.
- 6 x remote controlled gas switches (including remote fault indicators) at [CIC] per unit.

The capex estimate shown in Table 75. It is proposed that this project starts in FY27 and finishes in FY28.

Table 75: MSD1 Option 2 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	3.48	3.29	-	-	-	6.77	6.77

Source: AusNet analysis

11.5.1.2. Opex

Additional operating expenditure associated with option 2 has been estimated at 0.5% of the capex cost per annum as shown in Table 76.

Table 76: MSD1 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	-	-	-0.02	-0.02	-0.02	-0.06	-0.29

Source: AusNet analysis

11.5.2. Benefits

This option takes a similar approach to option 1, by targeting a solution at the section between Howqua Inlet and Kevington, which is a high impact area.

Instead of a fully underground solution, this solution offers a lower cost overhead express line as an alternative path when the primary path is subject to a fault. This solution will still be subject to fault causes by lightning, animals and vegetation, however the likelihood of faults occurring at the same time on separate physical routes is very low[18].

If the new 10km of express feeder sections can be targeted as an alternative path in the high impact 20km section, then the likelihood of an outage will greatly reduce.

Benefits were calculated in the same way as in option 1, and AusNet has accounted for the low probability that the new 6km express feeder section experiences a fault at the same time as the main feeder backbone.

The benefits have been calculated based on the historical outage data and the benefits of targeted undergrounding to customers on MSD1 beyond MS034. The benefits are shown in Table 77.

Table 77: MSD1 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	0.50	0.48	0.46	0.44	0.42	2.30	8.53

Source: AusNet analysis

11.5.3. Summary

Given the low cost of this option, and optimal targeting of express feeder sections as secondary supplies, it provides a positive NPV for customers as indicated in Table 78.

Table 78: MSD1 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	3.48	3.29	-0.02	-0.02	-0.02	6.71	6.48
Benefits	0.50	0.48	0.46	0.44	0.42	2.30	8.53
						NPV	**2.06**

Source: AusNet analysis

11.6. Preferred option (and sensitivity testing)

Option 2 which includes 10kms of targeted express overhead sections between Macs Cove and Kevington is the preferred option as it is technically prudent and favourable on an NPV basis as shown in Table 79.

[18] Excluding major event days.

Table 79: Net Present Value ($m, 2023-24 dollars)

	Central assumptions	Higher WACC	10% increase in capex	Comments
Do nothing	-	-	-	
Option 1 – 10 kms of targeted undergrounding of MSD1	-3.52	-4.14	-4.69	
Option 2 – 10kms of targeted express overhead sections between Howqua Inlet and Kevington	2.06	0.89	1.09	This is the preferred option under all scenarios

Source: AusNet analysis

12. NLA31

12.1. Identified need

Customers on the Newmerella feeder number 31 (NLA31), in the Gippsland area of Victoria, experience an average outage duration of 12.2 hours per annum. This is more than four times the outage impact experienced by the average AusNet customer.

The NLA31 feeder splits into two sections as shown in Figure 45 with the north section backed up with CNR3 and the south section radial through to Marlo and Bemm River. As shown in Figure 46, the major customer impacts are in the Marlo area.

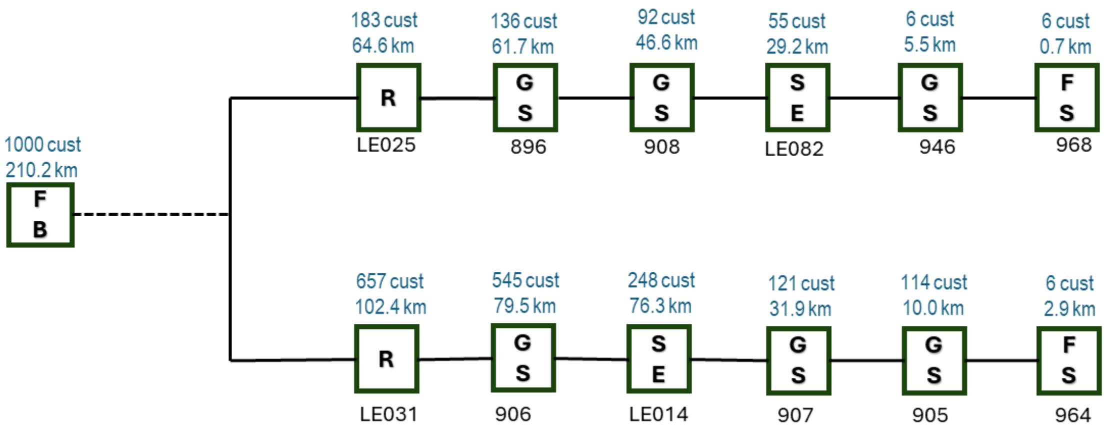


Figure 45: Representation of the NLA31 feeder

Figure 46: Outage heat map for NLA31

12.2. Options assessed

Given the majority of the impacts are in the Marlo area, we considered credible options to reduce the customer impacts in that area. Improving the supply to Marlo will also improve outcomes for downstream customers heading towards Bemm River, as the upstream supply will be more reliable. The north leg of the feeder includes an existing back feed from CNR3, so AusNet instead put the solution focus to the southern leg as it includes more customers and has more customer impacts. In summary, AusNet considered:

- Option 1: New overhead express feeder section from the Orbost area to Marlo
- Option 2: New feeder tie from the NLA31-CNR3 northern leg from Brodribb River to Marlo

Other options considered but discounted include:

- Feeder ties to Bemm River: This option was discounted due to the large distance to other feeders and the challenging terrain, which would result in a very high cost for a feeder tie versus the benefits.

12.3. Do nothing

Customers on NLA31 will continue to experience approximately $450K of economic impacts per annum under a do nothing scenario. The costs in Table 80 also includes the operational costs of outages at the same level as the past five years.

Table 80: NLA31 Do nothing scenario ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	0.11	0.10	0.10	0.09	0.09	0.49	1.65
Energy at risk	-0.45	-0.43	-0.41	-0.39	-0.38	-2.06	-7.65
						NPV	**-9.30**

Source: AusNet analysis

Table 81: NLA31 Do nothing scenario ($m, discounted, 2023-24 dollars) (using AusNet QCV Residential VCR)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	0.11	0.10	0.10	0.09	0.09	0.49	1.65
Energy at risk	-0.60	-0.57	-0.55	-0.53	-0.50	-2.75	-10.20
						NPV	**-11.85**

Source: AusNet analysis

12.4. Option 1: New overhead express feeder section from the Orbost area to Marlo

Option 1 includes a new overhead express feeder section from the main feeder backbone in the Orbost area through to Marlo.

12.4.1. Cost

12.4.1.1. Capex

AusNet used unit costs to develop the capital expenditure estimate for NLA31 option 1. The scope of work includes:

- 15 kms of overhead line at [CIC] per km.
- 3 x remote controlled gas switches (including remote fault indicators) at [CIC] per unit.

The capex estimate shown in Table 82. It is proposed that this project starts in FY27 and finishes in FY28.

Table 82: NLA31 Option 1 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	3.42	3.24	-	-	-	6.66	6.66

Source: AusNet analysis

12.4.1.2. Opex

Additional operating expenditure associated with option 1 has been estimated at 0.5% of the capex cost per annum. The opex shown in Table 83 is relative to the Do nothing case. The FY29-FY31 opex values appear negative as the values are relative to the Do nothing case. The values reflect the reduction in reactive fault costs after the project is completed.

Table 83: NLA31 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	-	-	-0.02	-0.02	-0.02	-0.05	-0.27

Source: AusNet analysis

12.4.2. Benefits

The location of the express feeder has been selected to target the high outage areas downstream of the LE031 and LE014 switches located in the Orbost and Marlo area. The inclusion of an express feeder between these two areas benefits customers downstream of Marlo for faults on the NLA31 feeder between Orbost and Marlo (LE031 and LE014 switches).

As shown in Figure 47 and Figure 48, inclusion of the express feeder enables the 248 customers downstream of LE014 to remain in service for the duration of the fault between LE031 and LE014.

The duration that the express feeder and this feeder section experience a fault concurrently has been excluded. This impact was quantified by assuming that both feeders experience the same fault rate per km and that the outage duration of each feeder is uniformly distributed across the year for simplicity. The benefits are shown in Table 84 and Table 85.

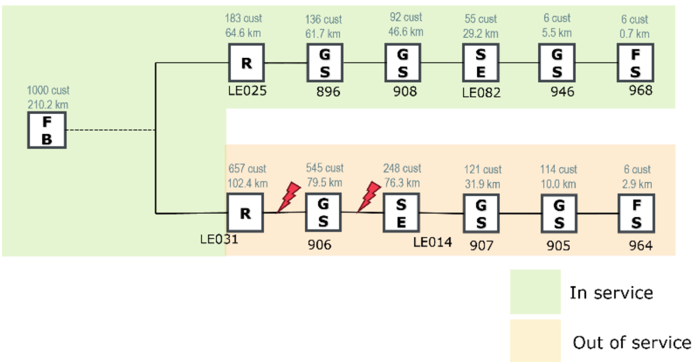


Figure 47: NLA31 feeder representation showing faults downstream of LE031

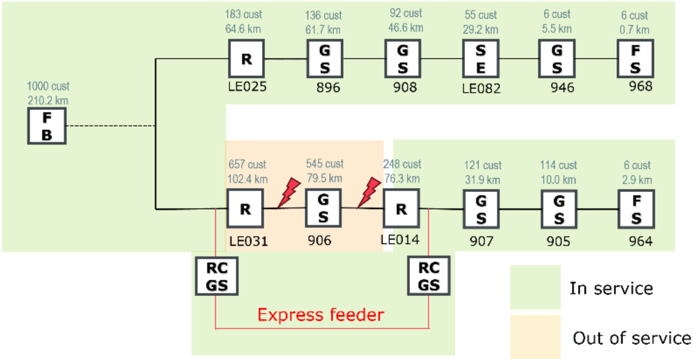


Figure 48: NLA31 feeder representation showing faults between LE031 and LE014

Table 84: NLA31 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	-	0.20	0.19	0.18	0.18	0.75	3.35

Source: AusNet analysis

Table 85: NLA31 Option 1 Benefits (using AusNet QCV Residential VCR), relative to Do Nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Benefits	-	0.27	0.26	0.24	0.23	1.00	4.47

Source: AusNet analysis

12.4.3. Summary

The high cost of a 15km 22kV overhead line and the associated switches required means that this option is NPV negative as indicated in Table 86 and Table 87.

Table 86: NLA31 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	3.42	3.24	-0.02	-0.02	-0.02	6.60	6.38
Benefits	-	0.20	0.19	0.18	0.18	0.75	3.35
						NPV	**-3.03**

Source: AusNet analysis

Table 87: NLA31 Option 1 Summary, relative to Do Nothing case (using AusNet QCV Residential VCR) ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	3.42	3.24	-0.02	-0.02	-0.02	6.60	6.38
Benefits	-	0.27	0.26	0.24	0.23	1.00	4.47
						NPV	**-1.92**

Source: AusNet analysis

12.5. Option 2: New feeder tie from the NLA31-CNR3 northern leg from Brodribb River to Marlo

Option 2 includes a new feeder tie from the northern leg of the NLA31 to CNR3 feeder through to the southern leg in the Marlo area. This solution includes a voltage regulator to manage the voltage when the feeder tie is in service. The existing conductor capacity (extending south from Brodribb and north from Marlo) has a lower rating than the standard feeder backbone. Using the voltage regulator, the feeder tie can pick up the contingency arrangement to Marlo based on the average demand (657 customers at an average 0.92kW per customer). We assumed that the feeder tie would be available 85% of the year. The percentage assumption is due to the limited capacity of the existing conductor, and it not having capacity to cover peak summer and winter demand periods. The requirement for conductor uprates will be assessed in future in line with the demand forecasts.

12.5.1. Cost

12.5.1.1. Capex

We used unit costs to develop the capital expenditure estimate for NLA31 option 1. The scope of work includes:

- 2kms of overhead line at [CIC] per km.
- 1.5kms of underground at [CIC] per km.
- 1 voltage regulator at [CIC].
- 5 x remote controlled gas switches (including remote fault indicators) at [CIC] per unit.

The capex estimate shown in Table 88. It is proposed that this project starts and finishes in FY27.

Table 88: NLA31 Option 2 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	3.07	-	-	-	-	3.07	3.07

Source: AusNet analysis

12.5.1.2. Opex

Additional operating expenditure associated with option 1 has been estimated at 0.5% of the capex cost per annum as shown in Table 89.

Table 89: NLA31 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	-	-0.05	-0.05	-0.04	-0.04	-0.19	-0.75

Source: AusNet analysis

12.5.2. Benefits

The location of the express feeder has been selected to target the high outage areas downstream of the LE031 and LE014 switches located in the Orbost and Marlo area. The inclusion of an express feeder between the northern backbone (switch 908) and the southern leg (906) aims to reduce the outage time experienced by customers downstream of switch 906 typically experienced due to the high fault region between LE031 and LE014.

As shown in Figure 49, inclusion of the express feeder enables the 545 customers downstream of 906 to remain in service for the duration of the fault between LE031 and 906.

As noted, the duration that the express feeder and this feeder section experience a fault concurrently has been excluded.

The benefits are shown in Table 90 and Table 91.

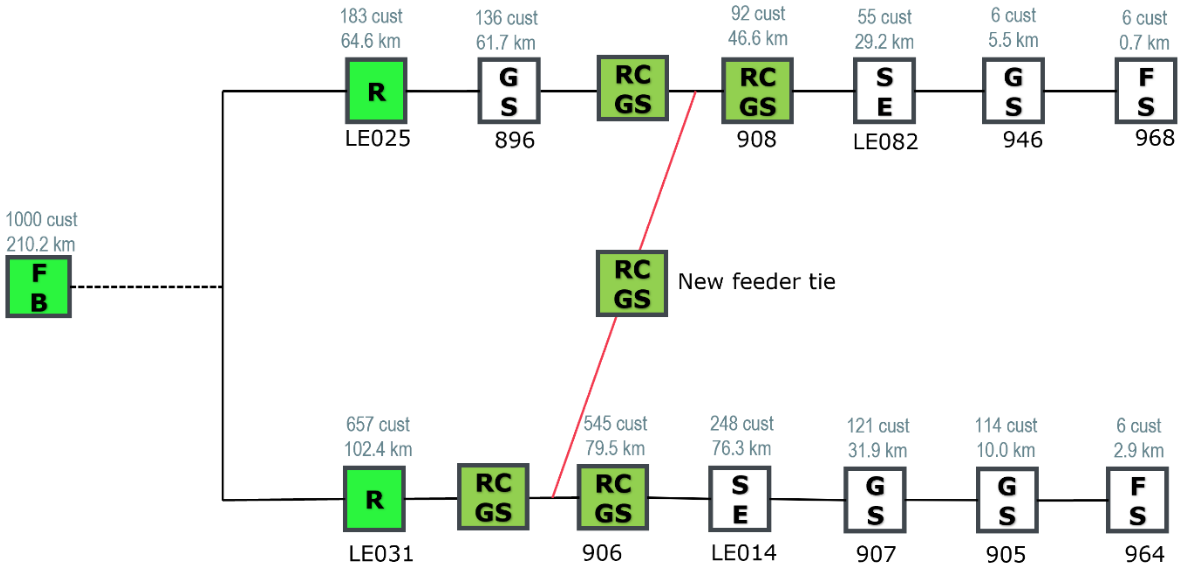


Figure 49: NLA31 solution option 2

Table 90: NLA31 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	-	0.20	0.19	0.18	0.18	0.75	3.35

Source: AusNet analysis

Table 91: NLA31 Option 2 Benefits, (using AusNet QCV Residential VCR), relative to Do Nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Benefits	-	0.27	0.26	0.24	0.23	1.00	4.47

Source: AusNet analysis

12.5.3. Summary

Given the relatively low cost of this feeder tie option, and optimal targeting to the high customer impact area, it provides a positive NPV for customers. A summary is shown in Table 92 and Table 93.

Table 92: NLA31 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	3.07	-0.05	-0.05	-0.04	-0.04	2.88	2.31
Benefits	-	0.20	0.19	0.18	0.18	0.75	3.35
						NPV	**1.04**

Source: AusNet analysis

Table 93: NLA31 Option 2 Summary, relative to Do Nothing case (using AusNet QCV Residential VCR) ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	3.07	-0.05	-0.05	-0.04	-0.04	2.88	2.31
Benefits	-	0.27	0.26	0.24	0.23	1.00	4.47
						NPV	**2.16**

Source: AusNet analysis

12.6. Preferred option (and sensitivity testing)

Option 2 is recommended as it is NPV positive as indicated in Table 94 and it provides the best benefit to customers on the NLA31 southern leg where there is no present back up supply.

Table 94: Net Present Value ($m, 2023-24 dollars)

	Central assumptions	Higher WACC	10% increase in capex	Comments
Do nothing	-	-	-	
Option 1 – New overhead express feeder section from the Orbost area to Marlo	-3.03	-3.51	-3.99	
Option 2 – New feeder tie from the NLA31-CNR3 northern leg from Brodribb River to Marlo	1.04	0.45	0.69	This is the preferred option under all scenarios

Source: AusNet analysis

13. WYK13

13.1. Identified need

Customers on the Woori Yallock feeder number 1 (WYK13), 56kms east of Melbourne CBD, experience an average outage duration of 15.7 hours per annum. This is more than five times the outage impact experienced by the average AusNet customer.

The WYK13 feeder runs through heavily vegetated terrain (as shown in Figure 51) and most of the customer minutes of supply occur due to the operation of the feeder circuit breaker or after sectionalisers WT231, WT006 and WT230 (which are represented in Figure 50).

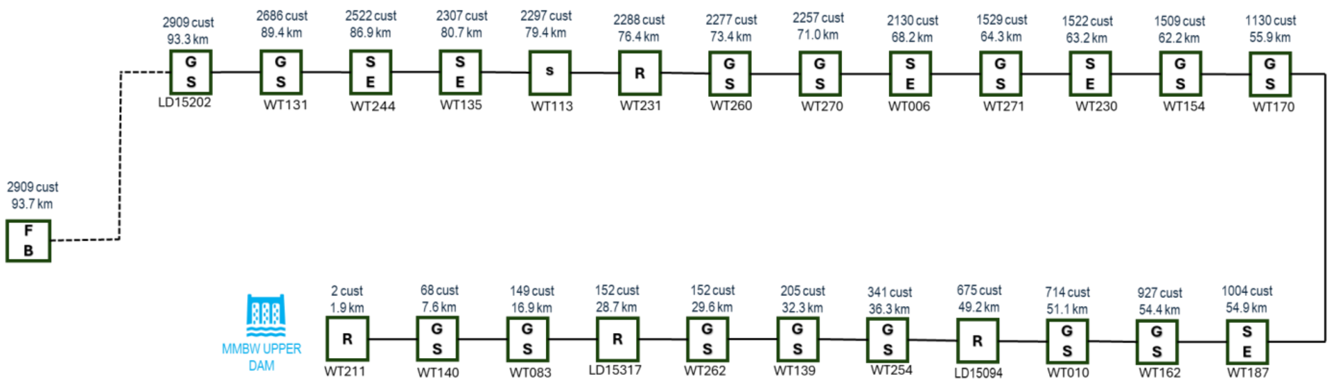


Figure 50: Representation of the WYK13 high voltage feeder (Present state).

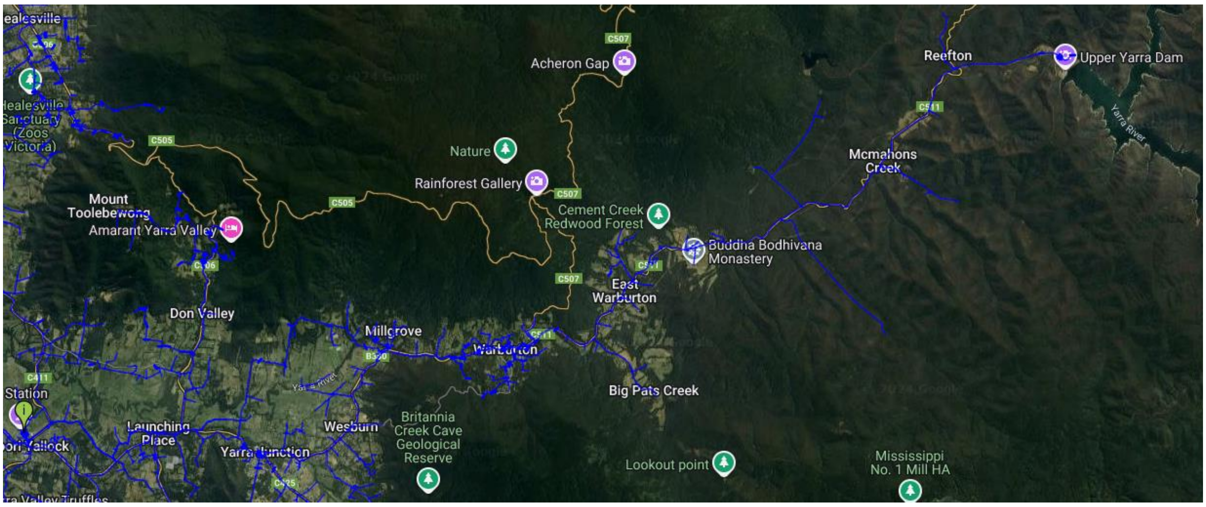


Figure 51: Map view of the WYK13 feeder showing the 22kV in blue.

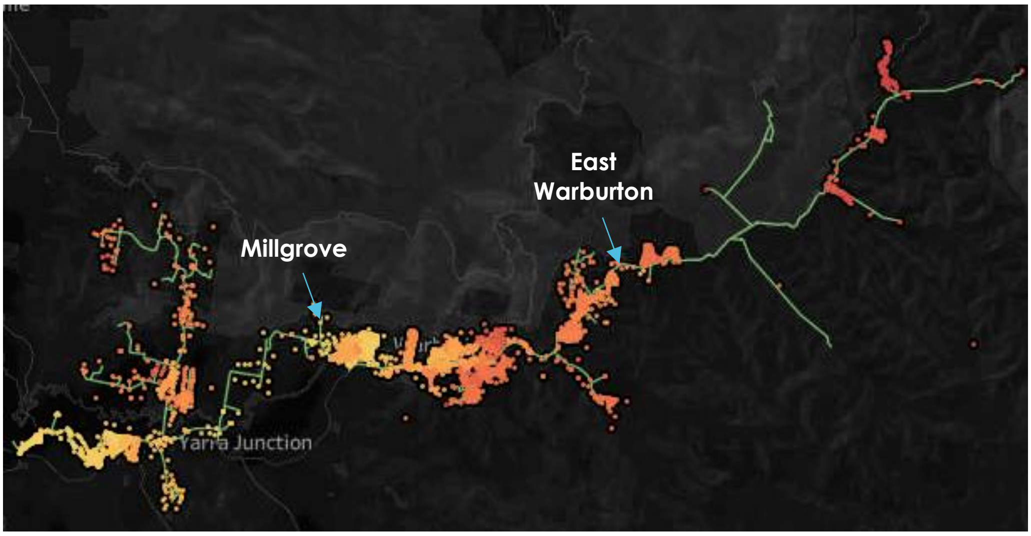


Figure 52: Customer outage heat map of the WYK13 feeder

13.2. Options assessed

Most of the customer impact is between Millgrove and East Warburton as shown in Figure 52. Noting this, AusNet considered the following credible options:

- Option 1: Extending the adjacent WYK23 feeder to East Warburton as a further backup supply and increase sectionalisation
- Option 2: Introducing an alternative underground route through heavily vegetated areas.

Other options considered but discounted include:

- An express feeder from WYK to provide additional backup. This was excluded as there is an existing backup up to Millgrove via the WYK23 feeder.

13.3. Do nothing

Customers on WYK13 will continue to experience approximately $1.2m of economic impacts per annum under a do nothing scenario. The costs in Table 95 also includes the operational costs of outages at the same level as the past five years.

Table 95: WYK13 Do nothing scenario ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	0.61	0.57	0.54	0.51	0.49	2.73	9.23
Energy at risk	-1.25	-1.20	-1.15	-1.10	-1.05	-5.75	-21.32
						NPV	-30.55

Source: AusNet analysis

Table 96: WYK13 Do nothing scenario ($m, discounted, 2023-24 dollars) (using AusNet QCV Residential VCR)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	0.61	0.57	0.54	0.51	0.49	2.73	9.23
Energy at risk	-2.10	-2.01	-1.92	-1.84	-1.76	-9.62	-35.66
						NPV	**-44.89**

Source: AusNet analysis

13.4. Option 1: Extend WYK23 feeder to East Warburton

Option 1 includes a new feeder extension from the WYK23 feeder at Millgrove to end of East Warburton to provide a backup supply to this highly impacted area. The solution will include remote controlled gas switches to enable sectionalisation. The locations of Millgrove and East Warburton are shown in Figure 52 and an estimate of the length of the feeder tie (via roadways) is shown in Figure 53. A representation of option 1 is shown in Figure 54.

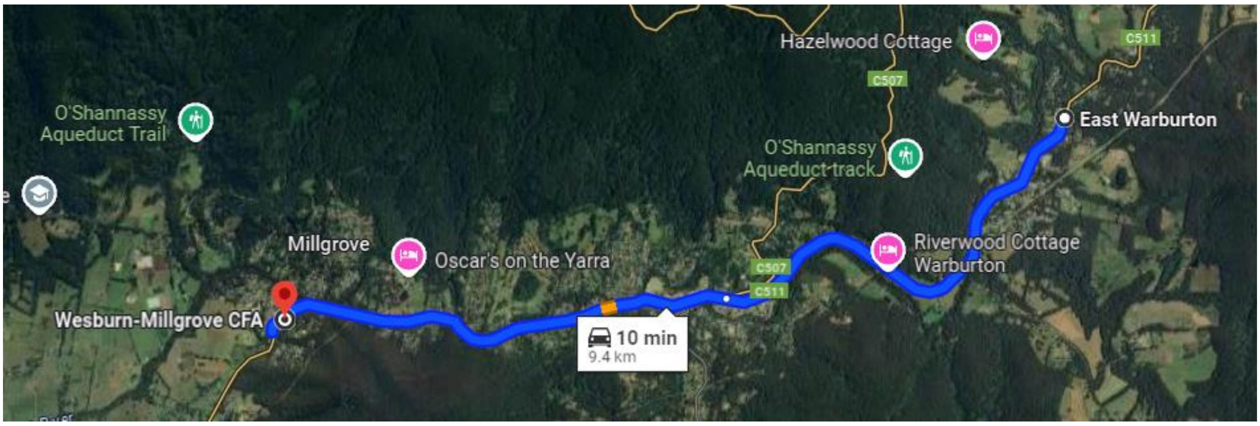


Figure 53: Estimate of the length of the extended WYK23 to WYK13 feeder tie

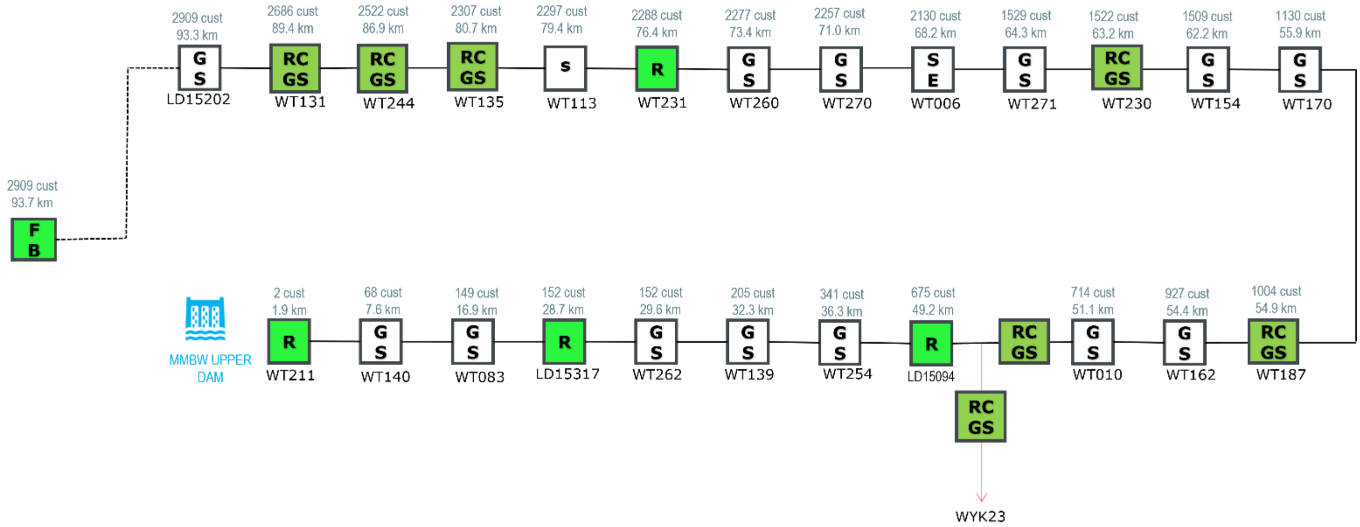


Figure 54: Option 1 representation for the WYK13 feeder

13.4.1. Cost

13.4.1.1. Capex

Unit costs were used to develop the capital expenditure estimate for WYK13 option 1. The scope of work includes:

- 10kms of overhead line for the new WYK23 to WYK13 feeder tie extension. Assume 5kms at covered conductor rate of [CIC] per km and 5km of standard conductor at [CIC] per km.
- 7 x remote controlled gas switches (to enable sectionalisation with the new feeder and feeder tie) at [CIC] per unit.
- 6 x REFCL remote fault indicators as WYK13 is a REFCL feeder, at [CIC] per unit.

The capex estimate shown in Table 97. It is proposed that this project starts and finishes in FY27.

Table 97: WYK13 Option 1 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	6.26	-	-	-	-	6.26	6.26

Source: AusNet analysis

13.4.1.2. Opex

Additional operating expenditure associated with option 1 has been estimated at 0.5% of the capex cost per annum. The opex shown in Table 98 is relative to the Do nothing case. The FY28-FY31 opex values appear negative as the values are relative to the Do nothing case. The values reflect the reduction in reactive fault costs after the project is completed.

Table 98: WYK13 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	-	-0.19	-0.18	-0.17	-0.16	-0.69	-2.82

Source: AusNet analysis

13.4.2. Benefits

The benefits associated with the feeder tie were calculated by reviewing the historical fault data for the WYK13 feeder in the sections between Millgrove and East Warburton.

It was assumed that the section between Millgrove and East Warburton can be split into three sections using remote controlled gas switches (combined with REFCL fault indicators).

Using remote control, the impacts of sustained faults can be limited to each section. This means that a fault in any of the new three sections will only impact customers in the faulted section, as electricity supplies are available on both sides. It also means that customers downstream of East Warburton can be supplied via the extended WYK23 when there is a fault in the Millgrove to East Warburton section.

Taking a similar sectionalisation approach, we assumed that the section between the feeder circuit breaker and Millgrove can be split to include three additional sections using remote controlled gas switches (combined with REFCL fault indicators). The existing WYK23 feeder that extends to Millgrove can be used as a back feed. The benefits are shown in Table 99 and Table 100.

Table 99: WYK13 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	-	0.31	0.30	0.28	0.27	1.16	5.19

Source: AusNet analysis

Table 100: WYK13 Option 1 Benefits (using AusNet QCV Residential VCR), relative to Do Nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Benefits	-	0.52	0.50	0.48	0.45	1.94	8.67

Source: AusNet analysis

13.4.3. Summary

The new WYK23-WYK13 feeder tie extension and additional sectionalisation across the feeder is NPV positive as shown in Table 101 and Table 102.

Table 101: WYK13 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	6.26	-0.19	-0.18	-0.17	-0.16	5.57	3.44
Benefits	-	0.31	0.30	0.28	0.27	1.16	5.19
						NPV	**1.74**

Source: AusNet analysis

Table 102: WYK13 Option 1 Summary, relative to Do Nothing case (using AusNet QCV Residential VCR) ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	6.26	-0.19	-0.18	-0.17	-0.16	5.57	3.44
Benefits	-	0.52	0.50	0.48	0.45	1.94	8.67
						NPV	**5.23**

Source: AusNet analysis

13.5. Option 2: Alternative underground route through heavily vegetated areas

Option 2 is similar to option 1, although it includes a new underground feeder extension from the WYK23 feeder at Millgrove to end of East Warburton to provide a backup supply to this highly impacted area. The solution will also include remote controlled gas switches to enable sectionalisation. The locations of Millgrove and East Warburton are shown in Figure 52 and an estimate of the length of the feeder tie (via roadways) is shown in Figure 53.

Undergrounding the WYK13 backbone was not a feasible solution as the undergrounded section would not be able to be used when REFCL is in service. This is due to the WYK13 feeder being at its REFCL capacitive current limit. Additional underground cable will introduce capacitive current to the feeder, meaning that the REFCL will not be able to perform to the mandatory performance requirements.

The alternative feeder tie route can still be used when the REFCL is not in service, outside of fire season. Therefore, this option proposes the use of an underground feeder tie connecting WYK13 to the nearby WYK23 feeder. A representation of option 2 is shown in Figure 55.

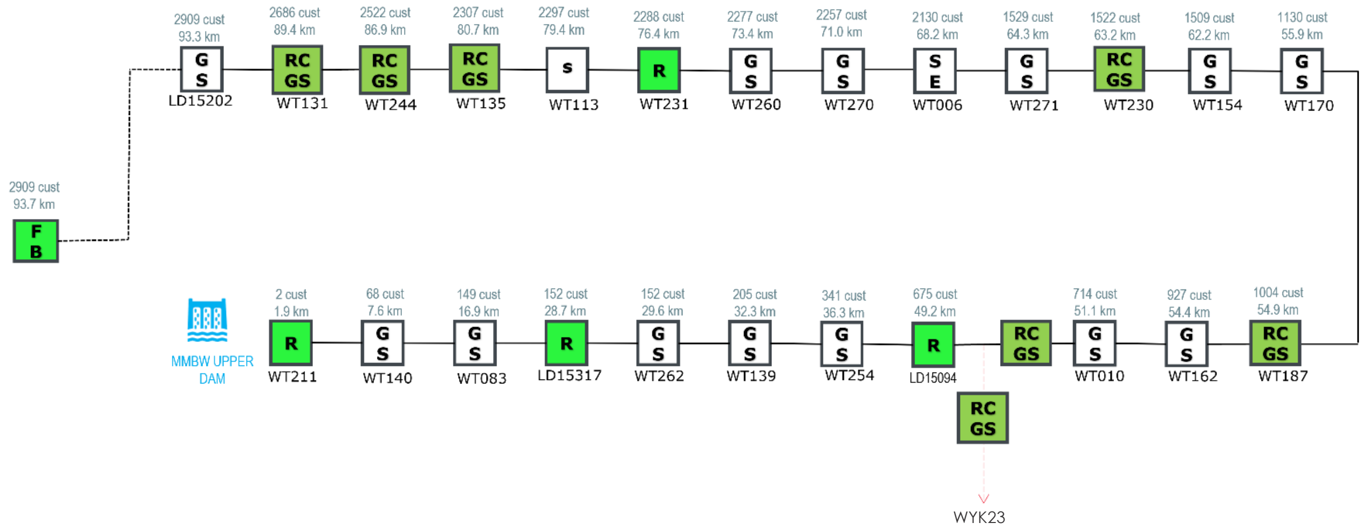


Figure 55: Option 2 representation for the WYK13

13.5.1. Cost

13.5.1.1. Capex

Unit costs were used to develop the capital expenditure estimate for WYK13 option 1. The scope of work includes:

- 10kms of underground cable for the new WYK23 to WYK13 feeder tie extension at [CIC] per km.
- 7 x remote controlled gas switches (to enable sectionalisation with the new feeder and feeder tie) at [CIC] per unit.
- 6 x REFCL remote fault indicators as WYK13 is a REFCL feeder, at [CIC]] per unit.

The capex estimate shown in Table 103. It is proposed that this project starts in FY27 and finishes in FY28.

Table 103: WYK13 Option 2 Capex ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Capex	4.26	4.04	-	-	-	8.29	8.29

Source: AusNet analysis

13.5.1.2. Opex

Additional operating expenditure associated with option 1 has been estimated at 0.5% of the capex cost per annum as shown in Table 104.

Table 104: WYK13 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	-	-	-0.11	-0.10	-0.10	-0.31	-1.61

Source: AusNet analysis

13.5.2. Benefits

The benefits for option 2 are assumed to be similar to option 1. The positive benefit of option 2 over option 1 is that the underground cable will be subject to less damage from weather, vegetation and animals. However, the overall benefit has been assumed to be less than option 1 as option 2 can only be fully utilised outside of fire season (i.e. only 75% of the year), due to the mandatory REFCL requirements. The benefits are shown in Table 105 and Table 106.

Table 105: WYK13 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	-	-	0.15	0.14	0.14	0.43	2.44

Source: AusNet analysis

Table 106: WYK13 Option 2 Benefits (using AusNet QCV Residential VCR), relative to Do Nothing case ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Benefits	-	-	0.25	0.24	0.23	0.71	4.08

Source: AusNet analysis

13.5.3. Summary

The high cost of providing a feeder tie means that this option is NPV negative as indicated in Table 107 and Table 108.

Table 107: WYK13 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	4.26	4.04	-0.11	-0.10	-0.10	7.99	6.68
Benefits	-	-	0.15	0.14	0.14	0.43	2.44
						NPV	**-4.24**

Source: AusNet analysis

Table 108: WYK13 Option 2 Summary, relative to Do Nothing case (using AusNet QCV Residential VCR) ($m, discounted, 2023-24 dollars)

	FY27	FY28	FY29	FY30	FY31	Total FY27-31	Full assessment period
Cost	4.26	4.04	-0.11	-0.10	-0.10	7.99	6.68
Benefits	-	-	0.25	0.24	0.23	0.71	4.08
						NPV	**-2.60**

Source: AusNet analysis

13.6. Preferred option (and sensitivity testing)

Option 1 is the preferred option as it is NPV positive (as shown in Table 109) and provides and optimal solution for the heavily impacted customers in between Millgrove and East Warburton and it provides a more reliable upstream supply for customers beyond East Warburton.

The sensitivity analysis shows that this option is favourable in all scenarios using a standard VCR. Using a substituted QCV rate for residential customers, increases the favourability of option 1.

Table 109: Net Present Value ($m, 2023-24 dollars)

	Central assumptions	Higher WACC	10% increase in capex	Comments
Do nothing	-	-	-	
Option 1 – Extend WYK23 feeder to East Warburton	1.74	0.60	1.23	This is the preferred option under all scenarios
Option 2 – Alternative underground route through heavily vegetated areas	-4.24	-4.80	-5.24	

Source: AusNet analysis

14. Customer insights and other considerations

The Worst Served Feeders business case proposes improvements to the electricity supply for the most outage impacted, vulnerable and remote customers in AusNet's distribution network area. To highlight this issue from a customer viewpoint and to describe the lived experience of poor reliability, the following sample of real customer quotes is shown:

- "Loss of food in fridge and freezer, not to mention the disruption of our lives having a child, tropical fish etc it causes considerable mental and financial duress"
- "Danger of being elderly and getting around with a lamp up and down stairs"
- "Unplanned Power outage led to Pharmacy medicines reaching temperatures outside of specifications, making them unfit for use"
- "We lost products in our fridges. We are on tank water, so we didn't have water"
- "[The business is a Retail Florist: stocking perishable fresh flowers] Being Valentines Day on 14th February, the store was unable to trade without power. We also did not have fridges running due to the power outage. All stock was lost from this incident along with having to outlay wages for staff"

Appendix A includes additional commentary and customer insights for each of the feeders identified as part of the Worst Served Feeders business case.

15. Evaluation

The proposed Worst Served Feeder program has an economic justification for forecast expenditure as per the requirements in the AER's Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution[19] (**Expenditure Guideline**).

In line with the Expenditure Guideline, the proposed program expenditure is prudent in that it reflects the best course of action via the:

- joint design of the program with customers and AusNet team members to ensure that the program targets the most outage impacted, vulnerable and remote customers in AusNet's supply area
- credible solution identification, development and assessment to ensure that preferred solutions are least cost technically acceptable.

The economic justification for this program is also aligned the Expenditure Guideline as it is quantitatively based and the net present value assessment is consistent with minimising the long run cost of achieving the expenditure objectives. Our analysis and quantitative approach included:

- Identification of the problems on each feeder using five years of historical outage information, excluding Major Event Days (**MEDs**).
- Credible solution identification and development using network information, engineering input and historical unit costs.
- An economic valuation of the customer benefits (excluding MEDs) 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 solutions are grouped as a Worst Served Feeder program of works as shown in Table 110.

Table 110: Worst Served Feeder Program Summary ($m, 2023-24 dollars[20])

Area	Feeder(s)	Preferred solution	FY27-FY31 Capex, $m
Bendoc	BM8B31	Installation of two remote controlled gas switches.	0.16
Cann River	CNR1, CNR2, CNR3	Augmentation in Cann River to extend the NLA31-CNR3 tie.	2.52
Kinglake	KLK11	Additional supply to the end of the Kinglake township and remote controlled gas switches on the north leg of KLK11.	1.98
Murrindindi	MDI1	SWER sectionalisation.	0.21
Moe	MOE13	New feeder tie to MOE21.	2.34
Mansfield	MSD1	10kms of targeted express overhead sections between Macs Cove and Kevington.	6.95
Newmerella	NLA31	New feeder tie from the NLA31-CNR3 northern leg from Brodribb River to Marlo.	3.07
Woori Yallock	WYK13	Extend the adjacent WYK23 feeder to East Warburton as a further backup supply and increase sectionalisation.	6.26
		Total cost of the program	**23.49**

In addition to the individual assessment, we also assessed the NPV of the Worst Served Feeder program of works as shown in Table 111.

[19] AER's Better Regulation Expenditure Forecast Assessment Guideline for Electricity Distribution, June 2024.
[20] Capex values are undiscounted.

Table 111: Worst Served Feeder Program Cost-Benefit Summary ($m, 2023-24 dollars)

	FY27 to FY31 (undiscounted)			Full assessment period (discounted)				
	Costs			Costs	Benefits and NPV: AER VCR Values		Benefits and NPV: AER VCR values for business and QCV for residential customers	
	Capex	Opex	Total cost	Total cost	Total benefits	NPV AER VCR Values	Total benefits	NPV AER/QCV Values
Do nothing	0.0	8.36	8.36	25.49	-104.58	-130.08	-145.94	-171.44
Worst Served Feeder Program	23.49	6.51	30.00	16.35*	20.62*	**4.27***	28.75*	**12.40***

*Source: AusNet analysis, * relative to the Do nothing case.*

The customer-AusNet led Worst Served Feeder program of works is both prudent and efficient based on the EACP criteria and the favourable cost-benefit analysis present in Table 111.

Considering the prudency and proven efficiency of the proposed program, AusNet's regulatory obligations and customer input from the EACP, AusNet considers that it is critical to seek funding for this program to improve outcomes for inadequately served customers within AusNet's supply area. Electricity is an essential service for customers and it is critical to the health of our customers and for public safety, it is important that we go as far as practicable to improve the service for customers on AusNet's worst served feeders.

16. References

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A. Appendix: Customer insights

This appendix includes commentary and customer insights for each of the feeders identified as part of the Worst Served Feeders business case. Real quotes from customers are included to describe the lived experience of poor reliability.

A.1. BM8B31 customer insights

The average outage duration on this feeder is extreme at nine times the outage impact experienced by the average AusNet customer. The low customer density means that a large economic investment such as a feeder tie is difficult to justify, however this business case demonstrates that an optimal switching investment can provide ongoing improvements for customers on this Bendoc BM8B31 feeder.

A.2. CNR1, 2, 3 customer insights

Real quotes from customers from the CNR supply area to describe the lived experience of poor reliability have included:

"The Power went out for 24 hours and we lost some food in our fridge because it got too hot. I was unable to cook so had to buy food at restaurants. We just borrowed a generator and brought fuel for it 20 minutes before the power came back on".

"I have had multiple power outages since the bushfires in 2020… in the last 3 years over 10 outages. We were told we would get reimbursed some money for this".

"There have been multiple outages across the year".

A.3. KLK11 customer insights

Real quotes from customers on KLK11 to describe the lived experience of poor reliability on this feeder have included:

"Loss of power over 12 hours. Disabled. Unable to cook."

"At approximately 4pm our power was cut off by a falling tree about 3km from our house. After a night of rechargeable lights and candles the power was restored around 4:30am."

"13 hour approx. power outage caused by fallen trees…whole area and beyond affected"

"Unplanned Power outage led to Pharmacy medicines reaching temperatures outside of specifications, making them unfit for use."

"A severe storm caused a fallen tree branch to sever the feeder into the property."

"Power outage (16 hours) all my food is off from both my fridges (2) and (2) freezers. Temperature was 28C"

"Electricity was lost for 2 days due to the weather"

"Power outage for 17 hours resulting in refrigerator being off and spoiling foods inside, including meat, prepared meals etc."

"Power outage for over 24 hours all food has gone off and I've had to dispose of all food"

"Unplanned power outage for approximately 48 hours".

A.4. MDI1 customer insights

The average outage duration on this feeder is high at almost five times the outage impact experienced by the average AusNet customer. The low customer density means that a large economic investment is difficult to justify, however this business case demonstrates that an optimal switching investment can provide ongoing improvements for customers on this MDI1 feeder.

A.5. MOE13 customer insights

Real quotes from customers on MOE13 to describe the lived experience of poor reliability on this feeder have included:

“After the storms that went across Victoria. We had no power for over 48 hours. We lost products in our fridges. We are on tank water, so we didn't have water.”

“Our power has been off 5 out of the last 7 days and is still off since 1pm Sunday night”

“There was a power outage from 3pm-5:30pm, when we returned to work the lights were all randomly flickering, the electrician could tell that there was damage to the lights and had to replace pieces”

“My fridge is completely dead after a storm and lights flickering”

“We had a power outage and when the power come back on my TV screen is half blue and half black and won't work”.

A.6. MSD1 customer insights

Real quotes from customers on MSD1 to describe the lived experience of poor reliability on this feeder have included:

“This is not the first time it has happened it happens often resulting in the loss of food in fridge and freezer, not to mention the disruption of our lives having a child, tropical fish etc it causes considerable mental and financial duress.”

"In the past 12 months there has been over 4-5 days of continuous power loss. Local outages and the big fire damage in Mid-December 2023”

“Due to the power outage the water to the golf green grass which has an automatic watering system and is additionally hand watered using bore water from a pump in times of high temperatures has significant dead areas requiring reseeding.”

“Power went out at about 1 pm and I have been told it won't come back on until Saturday evening”.

A.7. NLA31 customer insights

The average outage duration on this feeder is high at more than four times the outage impact experienced by the average AusNet customer. The low customer density means that a large economic investment is difficult to justify, however this business case demonstrates that an optimal feeder tie investment can provide ongoing improvements for customers on this NLA31 feeder.

A.8. WYK13 customer insights

Real quotes from customers on WYK13 to describe the lived experience of poor reliability on this feeder have included:

“Danger of being elderly and getting around with a lamp up and down stairs.”

“Having to performant a significant public event without proper grooming is a significant stress. Unable to use hair dryer which is not good for one performing in public!”

“Expenditure loss of $2000”

“9/10 Impact of power outage”

“Everything is dependent on electricity, so interruptions are very annoying and disruptive and frustrating. Having to depend on personal generators if not what a power company is supposed to do.”

“Long outages above 12 hours should only occur once every 3-5 years”

“Have more personnel to repair the problem when it occurs!”

“Significant 10/10 impact of power outage”

“Having to run a generator for that period of time to ensure we didn't lose food etc in the fridge/freezer was a cost. As was the need to travel outside of our area to collect fuel to run the generator. Trying to remain connected & informed regarding progress. Being unable to cook meals properly.”

“Long outages above 12 hours should only occur once a year”

“Being able to rely on the grid is always important. The ability to remain in touch & have a reliable grid to power everything from homes, internet, phones etc. is important.”

“Extended unplanned outage, with over $600 in food loss”

“Food spoilage from unplanned electricity outage”

“Heavy storm creating a power outage. Over $5,000 of stock was lost due to power outage. The business is a Retail Florist - stocking perishable fresh flowers. Being Valentines Day on 14th February, the store was unable to trade without power. We also did not have fridges running due to the power outage. All stock was lost from this incident along with having to outlay wages for staff.”

“Several brownouts in quick succession cause appliance failure at home”

“Power outage causing significant difficulties”

“Massive power outage”

"The storm and power outage I’m disabled injured and lost 2x Ozempic pens that were spoiled in the fridge they cost approx. $250”

“Power of for 2 days house was warm with having no power we on tank water to and my fridge got warm, so food has to be thrown out”

"Our power goes out a lot unexpectedly and also for planned outages. I work from home usually and when I lose power I have to drive 40 mins to the office for meetings. My partner often uses a 3D printer for work and runs models overnight and they lose so much productivity when they lose power and have to re-start everything the next day."

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