Business case: Worst Served Customers Reliability Improvement Programs

2025-30 Regulatory Proposal

Supporting document 5.9.5

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SA Power Networks

Empowering South Australia

Contents

Glossary

Acronym / term	Definition
AER	Australian Energy Regulator
Augex	Augmentation capacity expenditure
CAIDI	Customer average interruption duration index
Capex	Capital expenditure
CBD	Central business district
EDC	South Australian Electricity Distribution Code
ESCoSA	Essential Services Commission of South Australia
GSL	Guaranteed Service Level
LRF	Low reliability feeder
LT-LRF	Long-Term Low Reliability Feeders
MED	Major event days
NPV	Net present value
Opex	Operating expenditure
RLSR	Rural Long Supply Restoration
RCP	Regulatory Control Period
Repex	Replacement expenditure
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
STPIS	Service Target Performance Incentive Scheme
USAIDI	Unplanned System Average Interruption Duration Index
USAIFI	Unplanned System Average Interruption Frequency Index
VCR	Value of customer reliability

1 About this document

1.1 Purpose

This document provides business cases to support forecast expenditure for the 2025-30 Regulatory Control Period (**RCP**) on programs in the area of customer supply reliability. It functions as an integrated business case for three reliability improvement programs:[1]

1. Low Reliability Feeder Improvement program;
2. Rural Long Feeder Supply Restoration Improvement program; and
3. Regional Reliability Improvement program.

1.2 Expenditure category

This expenditure comprises of one input to our overall network augmentation capital expenditure.

1.3 Related documents

This document should be read in conjunction with the following documents that specifically relate to these programs, and together form a suite of supporting documents to our Regulatory Proposal to the Australian Energy Regulator (**AER**) for this program:

- Reliability forecasting structure - an overview of the approaches used to prepare the forecasts for the reliability improvement programs included in this business case;
- the Maintain Underlying Reliability Program business case - the business case for the augmentation expenditure (**augex**) program to maintain overall underlying reliability performance in the next RCP at historical levels, enabling us to meet Service Target Performance Incentive Scheme (**STPIS**) targets and our jurisdictional reliability targets;
- the business case for the Central business district (**CBD**) reliability Improvement program – a combined business case for the return the reliability performance of our CBD network to the jurisdictional reliability standard through a combination of cable replacement (**repex**) and automation (augex); and
- Essential Services Commission of South Australia (**ESCoSA**) Electricity Distribution Code (**EDC**) Version EDC/14[2] and the ESCoSA EDC review Final Decision.[3]

Table 1: Related documents

Ref	Title	Author	Version / date
[1]	5.9.1 - Reliability forecasting structure - Methodology	SA Power Networks	
[2]	5.9.3 - Maintain underlying reliability performance program - Business case	SA Power Networks	
[3]	5.3.12 - CBD Reliability - Business case	SA Power Networks	

1 Note, the business case functions as an integrated business case because of the similarities of the methods used to prepare the program forecast. The three programs however can be implemented independently of each other and are focused on improving supply to different worst served customer cohorts.

2 ESCoSA, *Electricity Distribution Code*, Version EDC/14, 1 July 2025.

3 ESCOSA, *Electricity Distribution Code Review*, Final Decision, June 2023.

2 Executive summary

This document provides business cases for three programs that aim to improve the supply reliability for different cohorts of our worst served customers:

- Low Reliability Feeder Improvement program;
- Regional Reliability Improvement program; and
- Rural Long Feeder Supply Restoration Improvement program.

Low Reliability Feeder Improvement program

The business case for the 2025-30 RCP Low Reliability Feeder Improvement Program recommends investing $9.1[4] million in augmentation capital expenditure (augex). This program will improve the reliability of supply to 13,013 of our worst served customers supplied by long-term Low Reliability Feeders. These customers represent a portion of our worst-served customers not addressed through the other proposed reliability improvement programs. [Note a total of 35,013 customers will benefit as upstream feeders are included in the program for improvement which are necessary to improve service to downstream long-term Low Reliability Feeders.]

Importantly, network upgrades under this program target performance improvements that are not sufficiently rewarded through the STPIS. Hence, this program's expenditure forecast forms part of our augex forecast.

This program targets our feeders that are consistently classified as Low Reliability Feeders, under the EDC,[5] the obligation to comply with which forms part of our jurisdictional regulatory requirements. The EDC defines 'Low Reliability Feeders' as feeders within a particular geographic region, which have exceeded twice the mean Unplanned System Average Interruption Duration Index (**USAIDI**) for that region for two consecutive financial years and require that we identify and monitor these feeders.[6]

While we may not have an explicit jurisdictional obligation to improve the supply from Low Reliability Feeders, there is still a general regulatory expectation that we examine potential actions to improve reliability on these feeders. This expectation stems from our reporting obligations to ESCoSA[7] [8], compliance with which is a condition of our electricity distribution licence.[9] This program responds to customers' concerns regarding consistently low reliability experienced by customers on Low Reliability Feeders, and the need to achieve improvements in reliability performance where it is efficient for customers to do so (that is, where benefits outweigh costs).

There are 107 feeders that we expect to be classified as Long-Term Low Reliability Feeders (ie feeders that have been classified as a Low Reliability feeder for more than two years over the last five years) as we enter the next RCP.

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4 All financial figures contained within this business case are in June 2022 dollars unless specified otherwise.

5 In its EDC review Final Decision (Electricity Distribution Code Review, Final Decision, June 2023), ESCOSA indicated that this definition will be moved from the EDC into ESCOSA's - Distribution Electricity Industry Guideline.

6 Electricity Regulatory Information – Requirements - Distribution Electricity Industry Guideline No. 1 Version: G1/13.1 12 February 2021

7 Electricity Regulatory Information – Requirements - Distribution Electricity Industry Guideline No. 1 Version: G1/13.1 12 February 2021

8 Electricity Industry Guideline No.1 Electricity Regulatory Information – Requirements – Distribution Proforma OP 2.5 requires SA Power Networks to annually report on Low Reliability Feeders, detailing each feeder's reliability performance and what actions have been taken or will be taken to improve reliability performance.

9 Electricity distribution licence issued by ESCOSA under the Electricity Act 1996 (SA) and last updated on 15 December 2022.

To develop the program forecast, credible solutions to improve our remaining long term Low Reliability Feeders have been analysed via a detailed review of the specific outage causes affecting that feeder and reliability improvement options feasibility assessment. We then evaluated three program options:

1. **'do nothing'** – do not upgrade any Low Reliability Feeders
2. **'optimal'** – upgrade only those Low Reliability Feeders where the benefits outweigh the costs
3. **'feasible'** – upgrade all Low Reliability Feeders where we have found feasible upgrade solutions [note, this provides the feasible upper limit of reliability improvement].

Our preferred program is option 2 'optimal', which only includes solutions found to be economically efficient (ie the benefits to customers supplied by these upgrades exceed the upgrade costs in Net Present Value, (**NPV**) terms). This program will improve the customer supply reliability where it is efficient to do so, to 66 of these Long-Term Low Reliability Feeders (**LT-LRF**) through a range of remediation works specific to the feeder and its outage causes. Improvement works include addressing recurrent outage causes &/or reducing the number of customers interrupted when outages occur.

The program will provide, on average, a 143-minute improvement to the current LT-LRF Unplanned System Average Interruption Duration Index (**USAIDI**) of 458 minutes per annum, representing a 31 percent improvement to these Long-Term Low Reliability Feeders supply reliability (including Major Event Days). We estimate the total economic benefit (ie value of avoided customer interruptions based on the Value of Customer Reliability (**VCR**) that will be delivered by this program is $38.2 million ($15.2 net) in present-value terms over the life of the proposed network upgrade.

Crucially, within these initiatives, enhancements to the network focus on performance improvements that may not receive adequate recognition through the STPIS as benefits are only be realised by SAPN up until STPIS Targets are revised in each RCP. In contrast, the VCR Benefit ensures continuous annual rewards for customers throughout the lifespan of the upgraded assets.

The program is a continuation of a program we commenced in the current RCP. The proposed $9.07 million forecast augex for this program represents a reduction from the $15.2 million 2020-2025 AER forecast included in its Determination which we are forecasting to spend in the 2020-25 RCP. This reduction is largely due to the lower number of feeders that have economically efficient upgrades identified in the next period.

The outcomes provided by this program align to the expectations of our customers as reflected in the People's Panel recommendations.

Regional Reliability Improvement program

The business case for the 2025-2030 Regional Reliability Improvement Program recommends an investment of $13.5 million in augex. This program is a new program for the next RCP to improve the reliability of supply to 23,220 of our customers in our worst served regional areas. These regions' performance will not be significantly addressed through the other proposed reliability improvement programs.

Importantly, network upgrades under this program will target performance improvements that would not be sufficiently rewarded through the STPIS, for the reasons stated above. Hence, this program's expenditure forecast forms part of our augex forecast.

We have obligations under our jurisdictional requirements to report the reliability of supply for feeders grouped into nine regions and Major Regional Centers across our network,[10] and compliance with this reporting obligation is a condition of our electricity distribution licence. This proposed program targets the

[10] Electricity Industry Guideline No.1 Electricity Regulatory Information – Requirements – Distribution Proforma OP 2.8 requires reporting on nine geographic regions and Major Regional Centres. Compliance with this reporting obligation is a condition of our electricity distribution licence.

regions that have experienced an appreciable decline in reliability recently or where the regional average reliability is significantly poorer than the overall regional averages.

Currently, we have no explicit obligation to improve the supply to these regions. This program responds instead to customers' concerns regarding the inequity in reliability performance experienced by customers in our worst served regions, and the need to achieve improvements in reliability performance where it is efficient for customers (i.e. benefits outweigh costs).

We have identified three reporting regions whose reliability service levels are significantly worse than the other seven regions, namely the South East, which has seen a decline in its performance recently, and Eyre Peninsula and the Upper North, which both have sustained performance much poorer than other regions.

To develop the program forecast, we identified feeders in each of these regions where improvements are efficient from a detailed review of the specific outage causes affecting that feeder and feasible mitigating network upgrades. We then evaluated three program options:

1. '**do nothing'** - do not upgrade any of the three regions
2. '**all three regions'** - improve performance in all three regions
3. **'two worst regions'** - improve performance in Eyre Peninsula and the Upper North, which we have found to be the two worst performing regions.

For options 2 and 3, we only included feeder upgrades found to be efficient (ie benefits to customers supplied by these upgrades exceed the upgrade costs in present value terms). Our preferred program is options 2 'all three regions', which will bring the reliability performance of all three regions more in line with similar geographical regions via a range of remediation works specific to the outage causes affecting poor performing feeders of those regions. These may be works to address recurrent outage causes or to reduce the number of customers interrupted when outages occur.

We have identified 50 feeders through this program where it is efficient to improve performance to the respective regions.

This program will improve performance in the three regions as follows:

- Eyre Peninsula will receive a supply reliability improvement of an average of 9% (System Average Interruption Duration Index (**SAIDI**) including Major Event Days (**MED**));
- Upper North will receive a supply reliability improvement of an average of 24% (SAIDI including MEDs); and
- South-East will receive a supply reliability improvement of an average of 5% (SAIDI including MEDs).

These improvements will bring these regions closer to the performance of other rural regions.

We estimate the present value of the total economic benefit, by way of the value of avoided customer interruptions based on the VCR due to the program, is $42.7 (gross) and $34.35 (Net) million over the life of the proposed network upgrades.[11]

The outcomes provided by this program align to the expectations of our customers as reflected in the People's Panel recommendations.

[11] The NPV analysis references a combination of assets with a life of either 15 or 25 years evaluated at discount rate of 4.05%.

Rural Long Feeders Supply Restoration Improvement program.

The business case for the 2025-30 Rural Long Feeders Supply Restoration (**RLSR**) improvement program recommends an investment of $4.3 million in augex. This program is a new program for the next RCP and will improve the reliability of supply to 10,230 customers in remote areas. These customers endure extended outage durations which will not be addressed through the other proposed reliability improvement programs.

Importantly, as network upgrades under this program will target performance improvements that would not be sufficiently rewarded by the STPIS (for the reasons stated above), we have included this program in our proposed augex. As discussed below, our proposed program works towards meeting the EDC supply restoration targets for Rural Long feeders, which are currently not being met, and delivers an outcome that our customers support where it is prudent and efficient to do so.

We have an obligation under the EDC to use all reasonable efforts, skills and resources to achieve minimum supply restoration time targets and thresholds in each and every regulatory year[12], and compliance with the EDC is a condition of our electricity distribution licence. We did not meet these supply restoration time targets for our Rural Long Feeders in either the 2020-21, 2021-2022 and 2022-23 regulatory years, and have also seen a declining trend over the longer term in the average restoration time for Rural Long feeders. This program therefore targets these feeders accordingly.

This program is supported by our customers as it responds to concerns regarding extended duration outages experienced by customers in remote parts of our network (i.e. supplied via Rural Long Feeders), and seeks to improve supply restoration times provided it is efficient to do so (i.e. benefits to customers outweigh costs). The program therefore seeks to make efficient and prudent progress toward meeting the EDC restoration time targets for Rural Long Feeders.

To develop the program forecast, we identified 334 Rural Long feeders with poor restoration performance and determined credible solutions to upgrade each of these feeders from a detailed review of the specific outage causes affecting those feeders and feasible mitigating network upgrades. We then evaluated three program options:

1. **'do nothing'** - do not upgrade any of those feeders
2. **'optimal'** - upgrade only those feeders where the benefits outweigh the costs
3. **'feasible'** - upgrade all of those feeders where we have found feasible upgrade solutions (note, this provides the feasible upper limit of reliability improvement).

Our preferred program is option 2 'optimal', which only includes upgrades to 44 Rural Long feeders found to be efficient (ie benefits to customers supplied by these upgrades exceed the upgrade costs in present value terms). This program will improve network restoration times to meet our jurisdictional targets by upgrading manually monitored and controlled switches to remote monitoring and controlled facilities. This will enable rapid identification and reporting of network outages, allowing earlier crew dispatch as well as reducing the time taken to travel to switches to confirm fault targets and restore supply. This will also allow us to immediately and remotely disconnect power supply in the event of a safety issue such as a farmer coming into contact with our equipment.

The preferred program is to upgrade 44 Rural Long feeders where restoration time improvement will not be improved through the other reliability improvement programs (eg Low Reliability Feeder Program or the Regional Reliability Improvement Program).

The preferred program will provide, on average, a 174 minute improvement in the current average USAIDI of 623 minutes per annum across these 44 feeders, representing a 28% improvement in their supply reliability (including MEDs). We estimate the total net economic benefit (i.e. value of avoided customer interruptions

[12] ESCOSA, *Electricity Distribution Code*, Version EDC/14, 1 July 2025, clause 2.2.

based on the VCR due to the program is $5.8 million in NPV terms over the life of the proposed network upgrades).[13]

Service Target Performance Incentive Scheme and Opex Adjustments

We anticipate the three improvement programs will produce a modest improvement to the underlying reliability measured through the STPIS and have calculated and included the downward adjustments to the STPIS targets for the next RCP.

Additionally, the Low Reliability Feeder Improvement and Regional Reliability Improvement programs should provide a small overall reduction in the current recurrent level of operating expenditure (**opex**), due to a reduction in network interruptions and associated reduced emergency response costs achieved by the programs. We are therefore proposing two negative step changes of -$0.06 million per annum to our opex forecast to allow for each of these programs.

[Note: the changes to opex and STPIS occur incrementally over the 2025-30 RCP as the programs are rolled out.]

3 Background

3.1 The scope of this business case

This business case responds to customers concerns and the need to improve reliability of supply to our worst served customers where efficient (i.e. where benefits outweigh costs) and / or where action is required to improve performance where EDC targets are consistently not being met so as to comply with jurisdictional reliability obligations / requirements. It considers options to improve the supply reliability for these customers through upgrades and modifications to our assets, covering three separate programs:

- Low Reliability Feeder Improvement Program, which improves supply reliability to our worst served customers supplied from our poorest performing feeders, known as Low Reliability Feeders (these are feeders that are consistently being classified as Low Reliability Feeders under our jurisdictional reliability requirements (see Section 3.3 for further details of these requirements);
- Rural Long Feeder Supply Restoration Improvement Program, which aims to achieve our jurisdictional supply restoration targets, improving the reliability of supply to our worst performing Rural Long feeders; and
- Regional Reliability Improvement Program, which improves supply reliability for customers in three of our poorest performing regions.

These three programs target different feeders (and therefore different customers (i.e. there is no double counting between the programs), where the specific feeders addressed via these programs are those feeders where:

- there is a net-benefit (in terms of the value of avoided customer interruptions based on the VCR) in improving the supply reliability provided by that feeder; and
- the STPIS would not provide sufficient incentive to undertake the necessary upgrades.

13 The NPV analysis references assets with a life of 15 years evaluated with a discount rate of 4.05%

This business case does not consider options to:

- maintain the underlying reliability performance in the next RCP at historical levels, and so enable us to meet the STPIS targets and our jurisdictional reliability requirements, which is considered in 'business case 5.9.3 – Maintaining Underlying Reliability Performance';
- improve supply reliability performance for CBD customers to comply with jurisdictional reliability requirements, which is considered in 'business case 5.9.4 - CBD Reliability Improvement';
- replace network assets to arrest the anticipated further decline in performance due to the aging and condition of the assets over the 2025-30 RCP, which is considered in our replacement expenditure (**repex**) programs covered in our 'business case 5.3.1 – Network asset replacement expenditure' ; nor
- address any forecast decline in performance through predicted climate change.

3.2 Our performance to date

The Low Reliability Feeders Improvement program is a continuation of a program we commenced in the current RCP (2020-25). We included an equivalent Low Reliability Feeders Improvement program in our Regulatory Proposal to the AER for the current RCP, which the AER accepted in making its Distribution Determination for the current RCP. The program forecast in our previous Regulatory Proposal was a $15.2 million program to upgrade 97 feeders, improving supply to 16,708 customers. This is progressing in line with the original forecast of the works to be undertaken, and we expect to spend circa $15 million in this RCP.

3.3 Drivers for change

3.3.1 Supply reliability and worst served customers

A key customer service level that we monitor and manage is the reliability of the electricity supply that we provide to our customers. This service level is typically measured in terms of the following two metrics:

- System Average Interruption Duration Index (**SAIDI**), the average duration that the average customer will not be supplied over a period; and
- System Average Interruption Frequency Index (**SAIFI**), the average number of interruptions to supply that the average customer will see over a period.

These measures provide an aggregate average reliability performance measure across groups of customers over a defined period (typically one regulatory year). However, depending on where customers are located and the extent of outages of the network supplying those customers, there can be significant variability in the supply reliability seen by individual customers and localised groups of customers.

Due to the random nature of outage events, any customer can have poorer supply reliability compared to other customers over short time periods. However, worst served customers are viewed as those that experience consistent medium to long term reliability issues, which tend to persist (and possibly) worsen over time, typically resulting in these customers having significantly poorer performance than their peers.[14].

Most notably for the programs discussed here, remote, and rural customers are typically prone to having the worst reliability of supply over the longer term. This is because these customers are typically supplied a long way downstream of bulk supply points by multiple long feeders, which are predominantly overhead bare conductor construction. These overhead arrangements, which are typically radial in design have no alternative points of supply and are far more prone to being interrupted by storms and so customers supplied from these longer feeders tend to have the poorest reliability of supply.

[14] For the avoidance of doubt, we do not have a jurisdictional definition of 'worst served customers' and have adopted this general definition here to aid in the classification of these three programs within this single business case.

We also have some metropolitan/urban customers, who receive supply reliability significantly worse than our typical metropolitan/urban customers. The metropolitan networks supplying these customers tend to be on the fringes of the metropolitan area supplying less densely populated areas with longer feeders transferring into rural areas which are more prone to the effects of weather compared to our typical metropolitan/urban networks.

Unfortunately, it is more costly to supply the sparsely populated rural regions and these outlier metropolitan areas, and therefore, there is a trade-off between the reliability of supply we can provide to these customers and the cost / price of providing this reliability. This tends to mean that the STPIS will often not provide sufficient incentive to improve supplies to these customers.

3.3.2 Driver of the Low Reliability Feeders Improvement Program

Low Reliability Feeders and relevant jurisdiction supply reliability requirements

We must comply with the EDC as a condition of our licence. The EDC defines various service standards we must comply with. These EDC reliability requirements, including reliability targets and thresholds, are summarised further in our Reliability Forecasting Structure document, which supports this program.

Under the EDC, a Low Reliability Feeder (**LRF**) is defined as an individual feeder with USAIDI performance (excluding Major Event Days (**MED**)) approximately twice as high as the 10-year average USAIDI for that feeder's region for two consecutive years, with ten separate SA regions defined via a Guideline published through the EDC[15]. The Guideline requires us to monitor each of our low reliability feeders that fall within this definition and, for each of these feeders, report the following annually:

- the Unplanned System Average Interruption Duration Index (**USAIDI**) and Unplanned System Average Interruption Frequency Index (**USAIFI**) performance (as at 30 June);
- the normalised USAIDI and USAIFI performance (as at 30 June);
- the geographic location of the feeder; and
- the actions we have already undertaken and/or any planned future actions to improve the reliability of the feeder.

We have been reporting this information to ESCoSA each year in our annual performance report, which is produced pursuant to Clauses 2.7.1 and 2.7.2 of our EDC.

We do not have specific jurisdictional regulatory obligations, under the EDC requirements or Guideline, to upgrade feeders classified as LRFs. However, there is still a general expectation in our jurisdictional regulations that we examine actions to improve reliability for customers on these feeders. Further, the NER permit us to put forward expenditure to improve reliability, where this is efficient for customers (benefits outweigh costs) and seeks to address the concerns of customers where customers support for improvement has been expressed through our engagement.

To ensure we are only identifying feeders that have consistently been classified as LRFs over the recent period, we have only considered feeders for upgrade under this Low Reliability Feeder Improvement Program that have been defined as LRFs under the EDC for at least two out of the last five years, which mean these feeders have exceeded twice the regional SAIDI at least 3 out of 5 years. We call these Long-Term Low Reliability Feeders (LTLRF) here.

It is important to note that this additional criterion that we have applied, results in a more conservative view of the candidate feeders for upgrade than the strict application of the EDC definition. That is, we are only assessing those feeders that have been classified multiple times as a LRF over the last five years.

[15] These regions are defined in Electricity Industry Guideline No.1

Recent Low Reliability Feeder performance

Figure 1a shows the number of feeders that have qualified as LRF each year since 2012/13 to 22/23, indicating that we have reduced the number of LRFs since a high of over 140 in 2013/14. But the number still persists to be around the 70 to 90 LRF's each year since around 2015/16.

Figure 1a: Historical number of Low Reliability Feeders

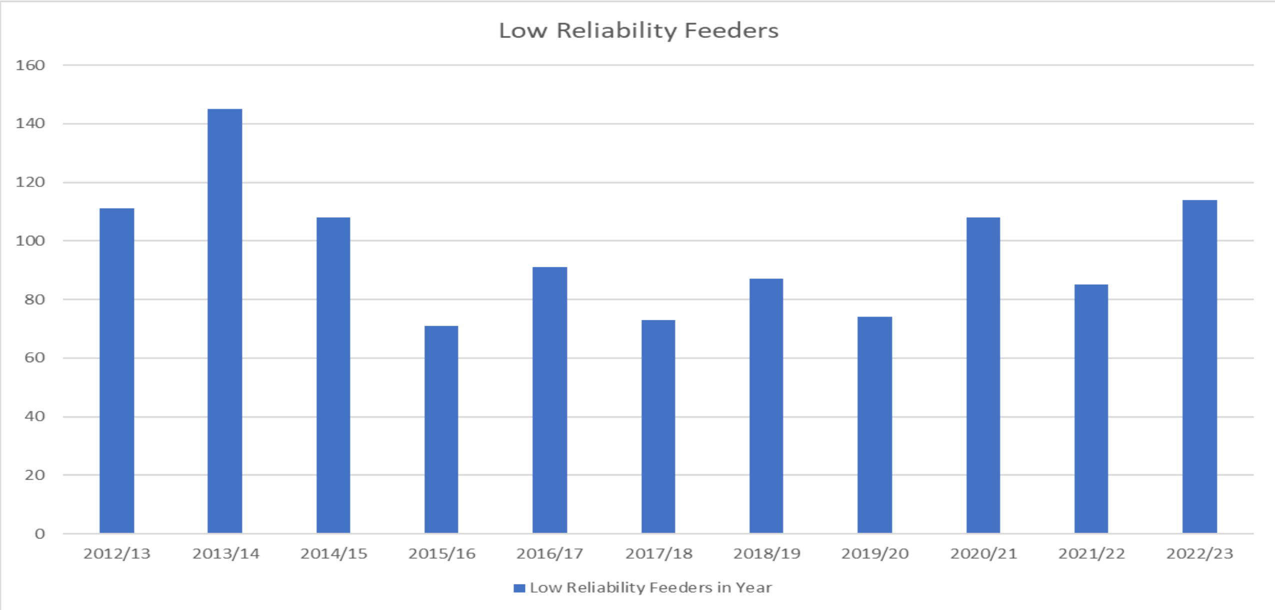


Figure 1b shows the number of feeders that have LRF qualified 2 or more times in most recent 5 Years that we classify as Long Terms-LRF's and the number we will upgrade through the current Low Reliability Feeder improvement program. Based on this information, we expect:

- there are currently 107 LTLRF supplying 23,319 customers;
- 27 of 107 LT-LRF will be mitigated as part of the 2020-2025 Low Reliability Feeders Improvement Program; and
- there will be 80 unmitigated LTLRF remaining on our network as we enter the next RCP.

Figure 1b: Forecast Long Term LRF's to end of current RCP (feeders qualified as LRFs 2 or more times in the past 5 years)

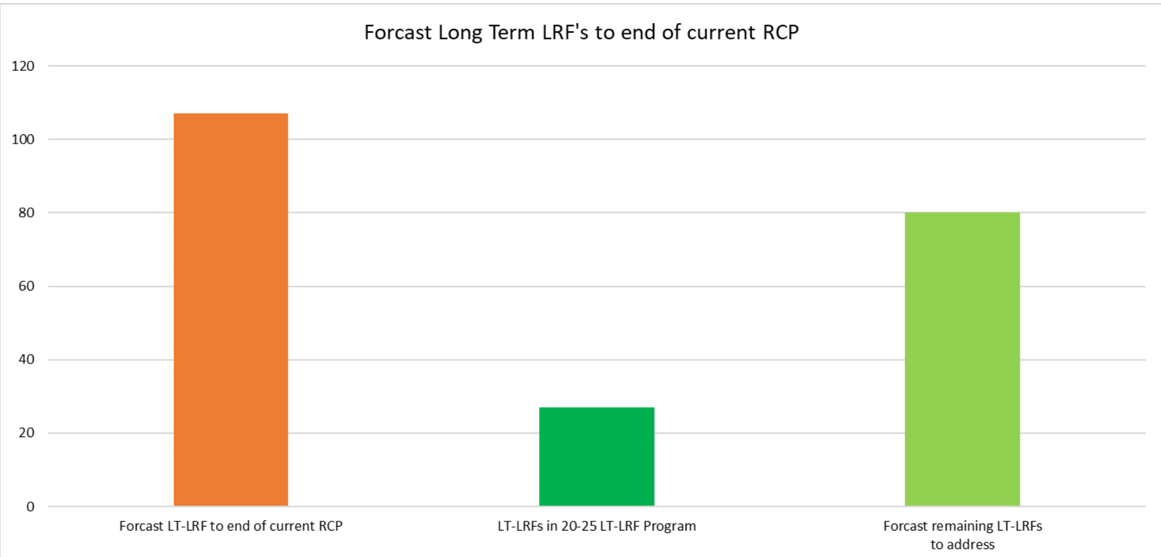
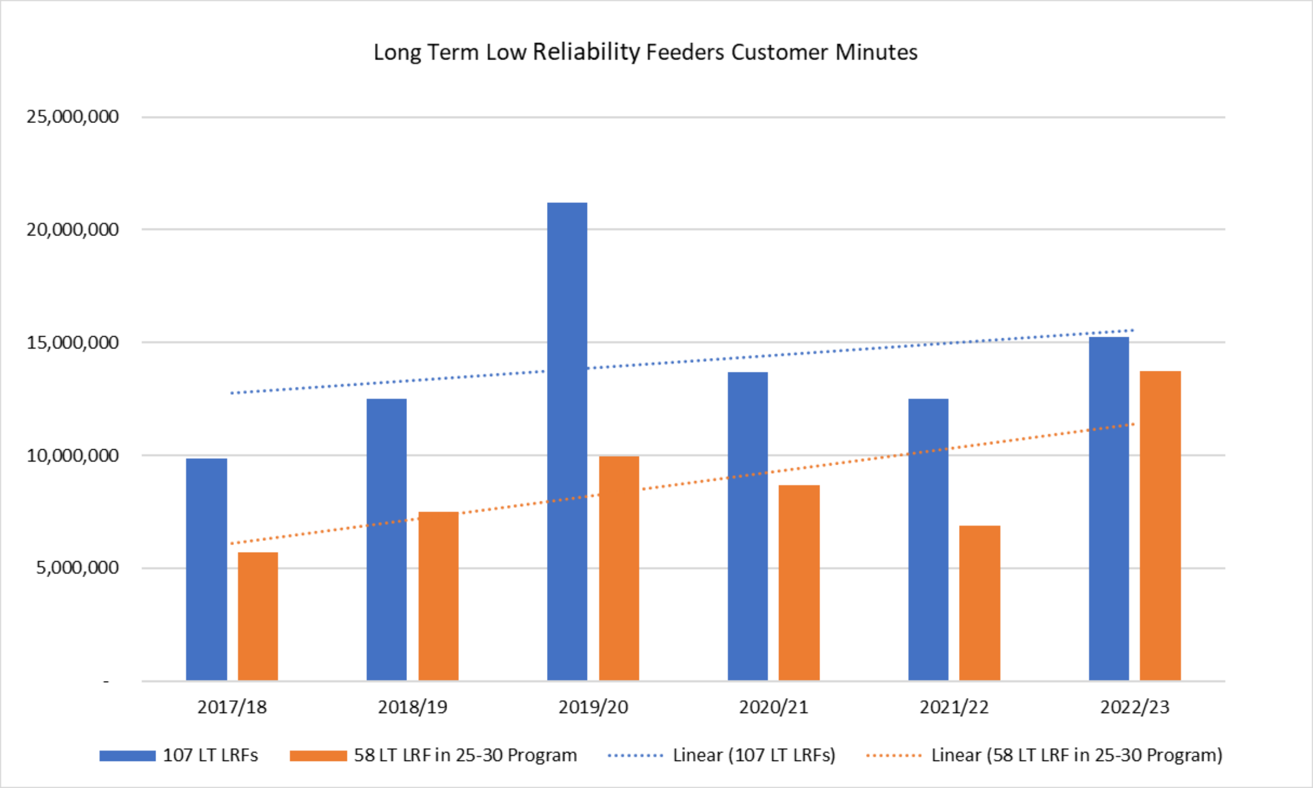


Figure 2 shows the annual aggregate customer minutes interrupted[16] for the current 107 LTLRFs. This chart shows that the customer minutes interrupted is increasing, and as such, without mitigating action could worsen further over the next RCP.

Figure 2: Customer minutes interrupted for Current Long-Term Low Reliability Feeders



[16] Customer minutes interrupted is calculated for each outage as the number of customers interrupted for that outage multiplied by the duration of the interruption. In this way it provides a view of the scale of the interruptions, and can be view as a measure that is proportional to the unsupplied energy to the customers.

Table 2 (regional) and Table 3 (feeder category) below summarises the average USAIDI for the 107 LTLRF relative to their regional or feeder category average performance.

Table 2: Regional performance – Low reliability feeders (annual average July 2015- June 2022) vs average network performance

	All Feeders in Region		Predicted LT LRF in next RCP		
Region	**Feeders in Region**	**Av Regional USAIDI (Incl. MEDs)**	**LT LR Feeders**	**LT LRF USAIDI (Incl. MEDs)**	**% Above Av Regional SAIDI**
Adelaide Business Area (ABA)	174	20	2	95	477%
Greater Adelaide Metropolitan Area (GAMA)	523	145	9	497	343%
Major Regional Centers (MRCs)	84	145	0		
Barossa, Mid-North and Yorke Peninsula (BMY)	323	274	15	901	329%
Eastern Hills (EH)	83	668	4	1,180	177%
Eyre Peninsula (EP)	142	625	29	1,802	288%
Fleurieu Peninsula (FP)	75	331	8	2,201	665%
Riverland and Murray lands (RM)	209	292	7	1,067	365%
South East (SE)	192	377	18	867	230%
Upper North (UN)	129	602	15	1,773	294%
Total	1,934		107		

Table 3: Feeder-category performance – Low reliability feeders (annual average July 2015- June 2022) vs average network performance

All feeders				107 Long Term Low Reliability Feeders				
Feeder Category	**Customers**	**Feeders**	**USAIDI (Incl. MEDS)**	**Feeder Category**	**Customers**	**Feeders**	**USAIDI (Ind. MEDs)**	**% Above Av Feeder Cat SAIDI**
CBD	6,876	181	20	CBD	95	2	95	477%
Urban	620,473	515	143	Urban	489	9	489	342%
Rural Short	130,404	766	274	Rural Short	973	17	973	355%
Rural Long	138,877	455	438	Rural Long	1535	79	1535	351%

The above demonstrates that our customers, served by these LT-LRF, are experiencing significantly poorer service levels than our average customers. However, as noted above, we are only guided to undertake significant corrective action where it is efficient. Therefore, to estimate the economic cost of this poor performance, we valued the interruptions to customer supplies on each of these feeders using the VCR for those feeders[17]. For this valuation, we have used the average annual customer minutes off supply for each feeder over the last-7-year period[18], including MEDs.

We estimate that the total economic cost due to this poor service is between $2.7 million to $3.2 million per annum relative to the performance we provide to the average customers of the relevant region &/or feeder type. The breakdown of this economic cost across the various regions and feeder categories is shown further in Table 4 and Table 5 below.

Table 4: Average annual economic costs comparison – regions

	Customers supplied by other feeders				Customers supplied by LTLRF				
	Total Customers	Average annual VCR impact per customer	total annual VCR impact		Total Customers	Average annual VCR impact per customer	total annual VCR impact		Total annual VCR impact relative to non-LTLR
Adelaide Business Area (ABA)	12,638	$ 197	$ 2,493,741		94	$ 992	$ 92,764		$ 74,313
Barossa, Mid-North and Yorke Peninsula (BMY)	59,750	$ 250	$ 14,926,979		1449	$ 521	$ 755,281		$ 393,408
Eastern Hills (EH)	31,185	$ 558	$ 17,399,761		739	$ 765	$ 565,519		$ 153,192
Eyre Peninsula (EP)	13,798	$ 575	$ 7,929,747		2325	$ 894	$ 2,077,262		$ 741,317
Fleurieu Peninsula (FP)	33,617	$ 198	$ 6,664,015		1352	$ 891	$ 1,204,248		$ 936,332
Greater Adelaide Metropolitan Area (GAMA)	586,327	$ 134	$ 78,639,180		9190	$ 261	$ 2,399,762		$ 1,167,249
Major Regional Centres (MRCs)	86,645	$ 213	$ 18,481,559						$ -
Riverland and Murraylands (RM)	38,398	$ 492	$ 18,898,529		600	$ 696	$ 417,441		$ 122,383
South East (SE)	26,116	$ 457	$ 11,924,630		6773	$ 304	$ 2,058,840		$ (1,033,560)
Upper North (UN)	11,139	$ 499	$ 5,556,737		801	$ 665	$ 532,099		$ 132,766
Grand Total	**899,610**	**$ 203**	**$ 182,914,878**		**23319**	**$ 390**	**$ 9,105,879**		**$ 2,687,401**

Table 5: Average annual economic costs by comparison - feeder categories

	Non LT LRF				LT LRF					
Feeder Cat	VCR pa	Customers	VCR per Customer		VCR pa	Customers	VCR per Customer		VCR if LT LRF at Non LT LRF VCR Rate	VCR differnace if LT LRF = Non LT LRF
CBD	$ 3,014,592	17,995	167.5		$ 92,764	94	$ 992.1		$ 15,663	$ 77,100
Rural Long	$ 8,318,574	26,769	310.8		$ 3,374,812	5,600	$ 602.6		$ 1,740,222	$ 1,634,590
Rural Short	$ 87,819,723	261,016	336.5		$ 3,244,795	8,438	$ 384.5		$ 2,838,999	$ 405,796
Urban	$ 83,761,988	593,830	141.1		$ 2,393,508	9,188	$ 260.5		$ 1,295,932	$ 1,097,576
Grand Total	$ 182,914,878	899,610			$ 9,105,879	23,319			$ 5,890,817	**$ 3,215,062**

17 This VCR value uses the 2022 VCR by customer type data published by the AER, and data from our own systems on the equivalent customers types supplied by each feeder.

18 This customer minute annual average is multiplied by the average consumed kilo-watt hours (kWh) per minute relevant to that feeder to produce an estimate of the kWh not supplied, which can then be multiplied by the VCR to produce a total economic cost.

3.3.3 Driver of the Rural Long Feeders Supply Restoration Improvement Program

Supply restoration and relevant jurisdiction supply reliability requirements

The EDC prescribes separate targets and reporting thresholds for the supply restoration time (called Network Restoration Time in the EDC) for each of the four feeder categories, CBD, Urban, Rural Short and Rural Long. The requirements define the minimum targets for supply restoration for each feeder category that should be achieved in each and every regulatory year – that is, the percentage of that feeder category's customers that should experience an unplanned interruption exceeding a specified time in hours during each regulatory year, as shown in Table 6.

We have an obligation under the EDC to use all reasonable efforts, skills and resources to meet these targets in every regulatory year. We also have an obligation under the EDC to report on how we have used all reasonable efforts, skills and resources if we fail to meet the reporting thresholds.

Table 6: Jurisdictional network restoration time targets and thresholds

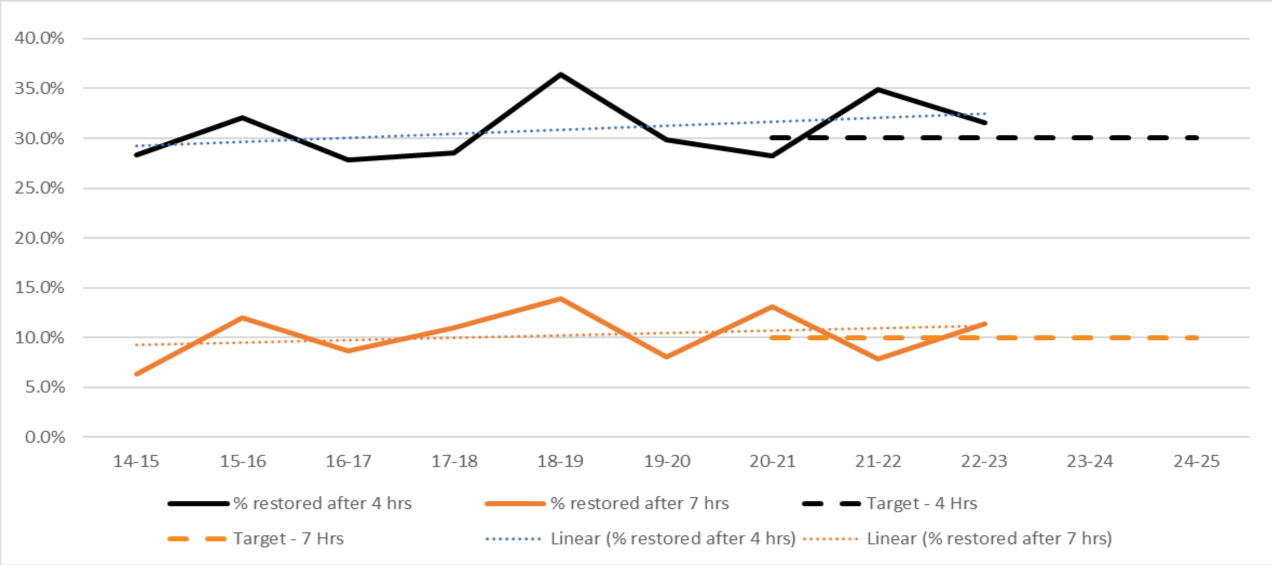
		% of total customers in feeder category per annum			
		CBD	**Urban**	**Rural Short**	**Rural Long**
=> 1 hour	Target	11			
	Reporting threshold	13.5			
> 2 hour	Target	4	27		
	Reporting threshold	6.5	29.5		
> 3 hour	Target		11	27	
	Reporting threshold		13.5	29.5	
> 4 hour	Target				30
	Reporting threshold				32.5
> 5 hour	Target			8	
	Reporting threshold			10.5	
> 7 hour	Target				10
	Reporting threshold				12.5

In any event, the NER permit us to put forward expenditure to improve restoration performance, where we are consistently not meeting EDC targets, the extent of the improvement is efficient for customers (i.e. benefits outweigh costs) and the expenditure addresses the concerns and expectations of customers as expressed via our engagement process.

Historical Supply Restoration time performance

Figure 3 shows our annual reported performance against the EDC supply restoration target for Rural Long feeders, since 2012-13. This chart shows that we exceeded the 4-hour EDC supply restoration target for Rural Long feeders in 2021-22 and 2022-23, with 35% of Rural Long customers restored in over 4 hours compared to the EDC target of no more than 30% of customers. The percentage of customers restored after 7 hours also exceeded EDC targets in 2020-21 and 2022-23.

Figure 3: Rural long network restoration - Percentage of total customers > 'X' Hrs



One-off breaches of the restoration target can occur, driven by the severity of conditions in that year. However, concerningly, Figure 3 also shows that there is a worsening trend in the percentage of customers exceeding the 4-hour target and a marginally worsening trend in the percentage of customers exceeding the 7-hour target. The continuation of these trends into the next RCP suggests both the likelihood of exceeding the targets and that the extent by which they will be exceeded is very likely to increase (albeit more marginally with the 7-hour target). This suggests that, without action, we could exceed the targets, even when conditions (eg weather) during a year are relatively benign.

3.3.4 Driver of the Regional Reliability Improvement program

Relevant jurisdiction regional reliability requirements

Under the Guideline[19], we have obligations to report the reliability of supply for ten regions across our network. Seven of these regions cover mostly rural and remote areas:

- Barossa and Mid-North
- Eastern Hills
- Eyre Peninsula
- Fleurieu Peninsula (including Kangaroo Island)
- Riverland and Murraylands
- South East
- Upper North.

The other three regions cover our more densely populated and urban areas:

- Adelaide Business Area (cover the set of CBD feeders)
- Adelaide Metropolitan Area
- Major Regional Centre's (includes the townships of Pt Lincoln, Whyalla, Pt August, Pt Pirie, Murray Bridge, Mt Gambier, Stirling-Aldgate, Mt Barker and Victor Harbor).

[19] ESCOSA Guideline No.1 Electricity Regulatory Information – Requirements - Distribution

The Guideline requires us to report quarterly and annually on the monthly and annual SAIDI[20] and SAIFI[21] (excluding MEDs) for each of the ten regions. These requirements do not define regional targets and we do not have specific obligations, under the EDC requirements, to upgrade our network to improve the reliability of specific regions. However, as part of this reporting, we set out the regional performance against the historical average and discuss the trends in performance, including the causes of significant variations.

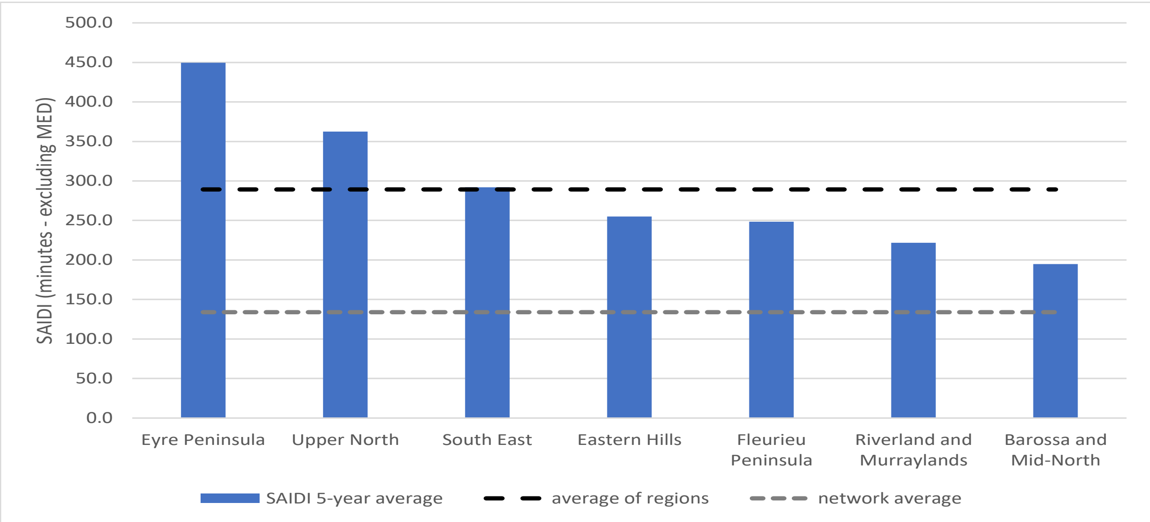
Although there is no strict compliance obligation around managing regional reliability, the reported regional performance (both in terms of the annual trend and performance relative to other regions) is an important matter for our customers. As such, the regional performance is often the subject of discussion with customers in those regions, particularly the poorest performing regions[22].

Historical regional reliability performance

Figures 4 and 5 show our average SAIDI and SAIFI (excluding MEDs), respectively, for the seven rural regions over the 5-year period from 2018-19 to 2022-23[23]. These figures also show the average reliability across these seven regions (ie the average of the regional 5-year averages) and the overall network average (including all ten regions).

These charts show that the Eyre Peninsula, Upper North and South East are the three worst performing regions in terms of their recent SAIDI performance. Eyre Peninsula and Upper North having particularly poor SAIDI performance relative to other regions, with Eyre Peninsula 160 minutes worse than the average of the seven regions (450 minutes compared to 289 minutes) and Upper North 73 minutes worse than this regional average (363 minutes compared to 289 minutes). Although Eyre Peninsula and Upper North have relatively better SAIFI performance, the South East has the worst SAIFI performance compared to other regions, with South East customers experiencing on average 1.8 interruptions per annum over the last 5 years compared to the average for all seven regions of 1.4 (ie 34% higher SAIFI).

Figure 4: Average 5-year USAIDI of the seven rural regions



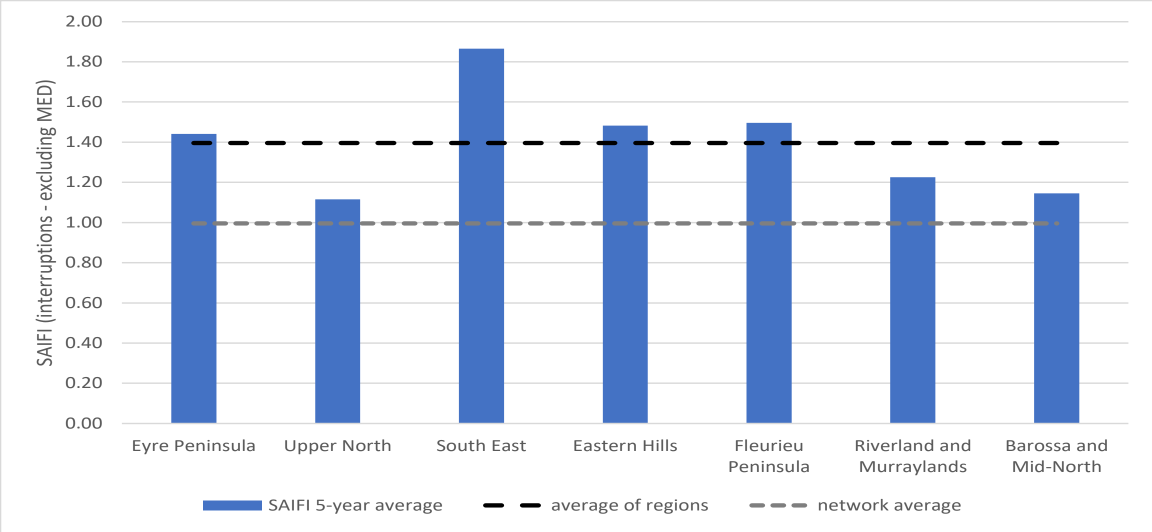
[20] SAIDI is the (Unplanned) System Average Interruption Duration Index, which reflects the average time in minutes that customers are without supply (over the defined period).

[21] SAIFI is the (Unplanned) System Average Interruption Frequency Index, which reflects the average number of interruptions to supply that customers experience (over the defined period).

[22] For example, this feedback arises from interaction with the Customer Advisory Boards, Regional Councils, development and Business Groups, individual customers, and through the 2017 Eyre Regional Reliability Review.

[23] 2022-23 reliability in this document reflects our estimate of the reliability in that year, based on the recorded actual performance to April 2023, and an estimate for May and June based on historical averages for this period.

Figure 5: Average 5-year USAIFI of the seven rural regions



The longer-term trends in reliability of these three poor performing regions are shown in Figure 6 to Figure 8. These figures show that the performance of the Eyre Peninsula and Upper North had been improving generally to around 2019-20, but performance has moderated since that time and worsened in 2022-23.

Figure 6: Eyre Peninsula historical annual reliability

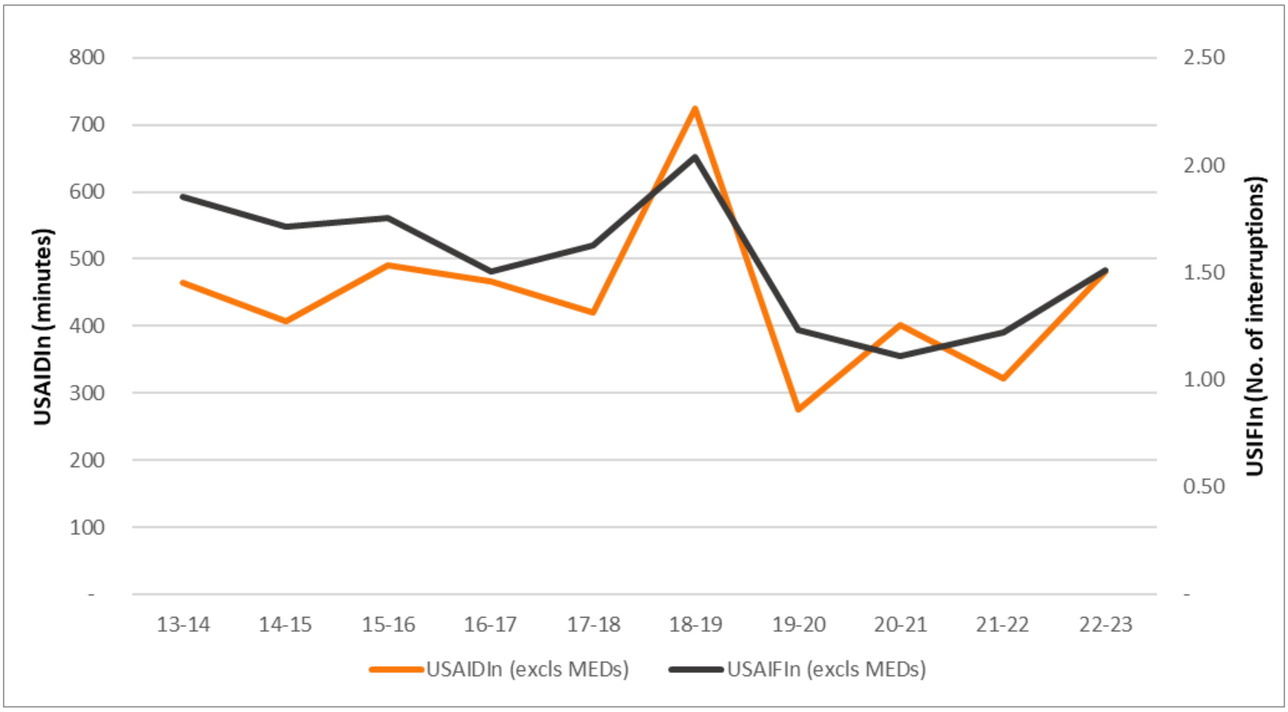


Figure 7: Upper North historical annual reliability

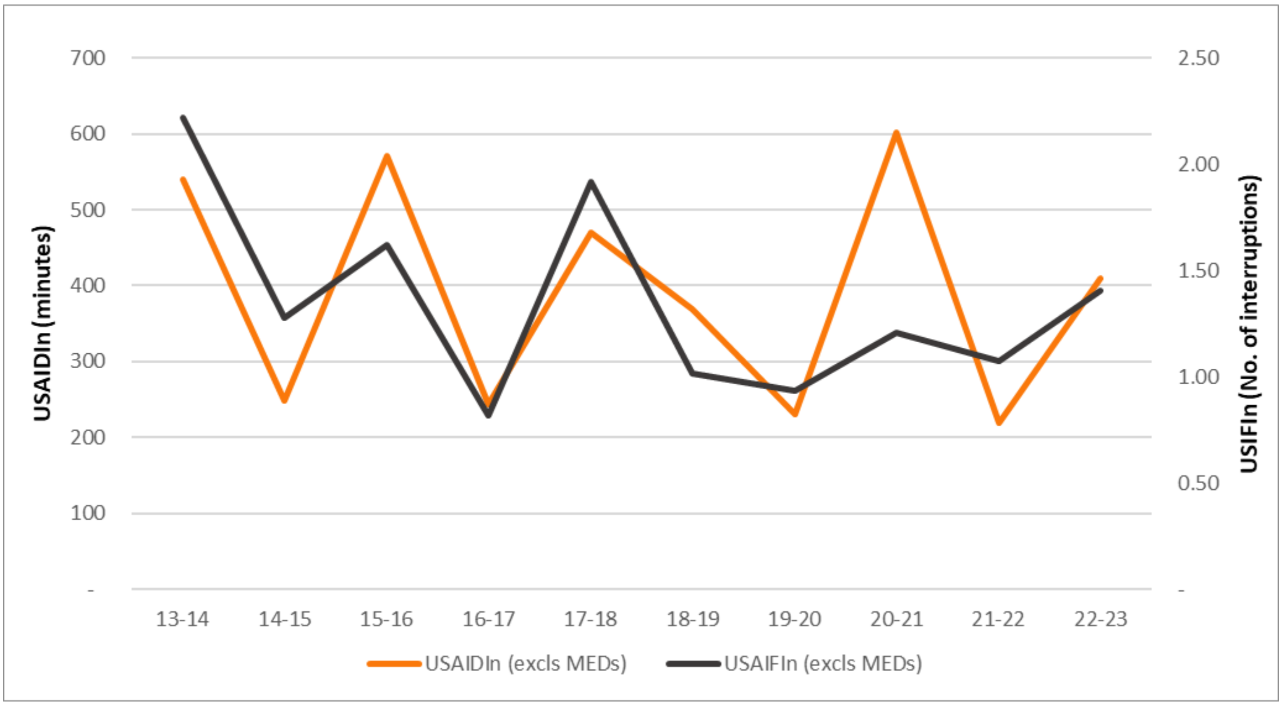
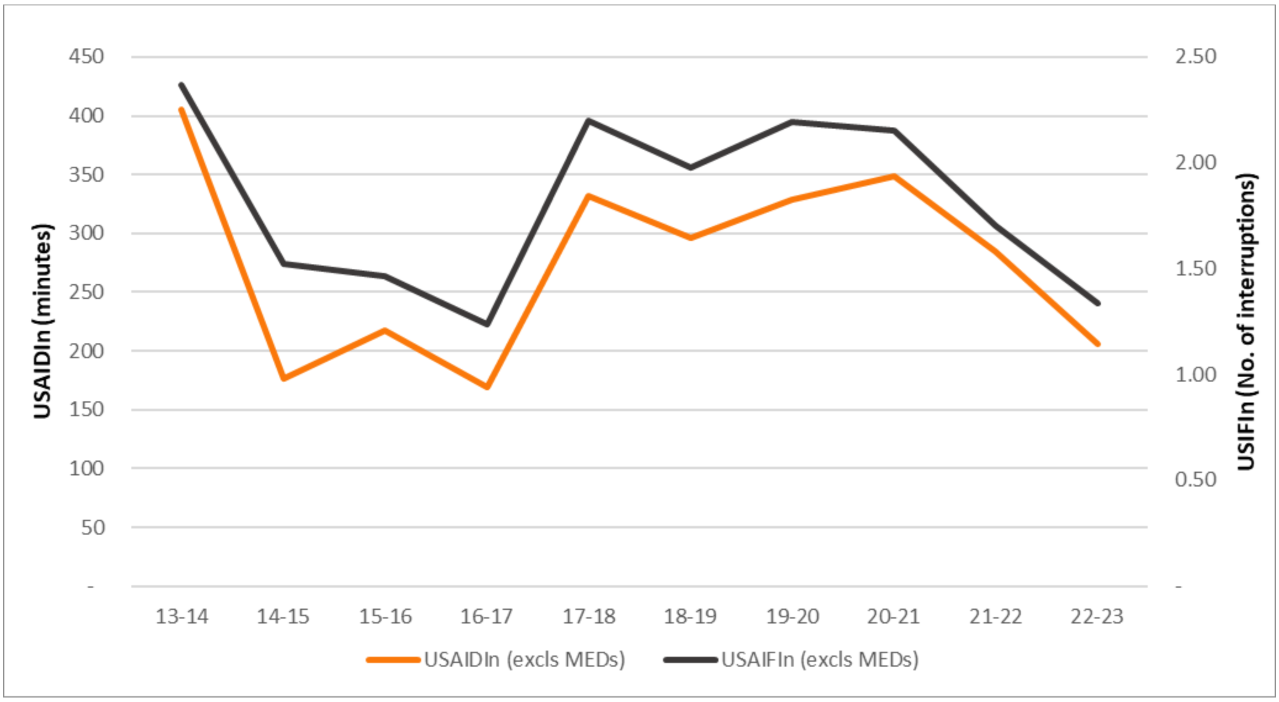


Figure 8: South East historical annual reliability



The performance of the South East region was improving to around 2016-17, but performance worsened considerably after that time. Our analysis of this decline found that performance had been impacted by severe weather events (mainly lightning strikes) and possum issues on sections of 33kV sub-transmission feeders.

In response to this decline, we have been installing lightning resistant insulators on selected sections of the 33kV sub-transmission system and installing possum guards on affected sections of lines to prevent possums climbing our Stobie poles. We are also installing feeder segmentation to reduce customers interrupted on some 33kV sub-transmission lines where the performance has been poor.

These upgrades have been undertaken in the current RCP under the 'maintain underlying' program, not a dedicated regional improvement program. The improved performance in 2021-22 and 2022-23 suggests that these recent upgrades could be arresting the decline. However, it is not certain at this time to what level of improvement has been achieved [24].

Furthermore, the upgrades were prioritised because they were sufficiently incentivised under the STPIS (ie the STPIS 'reward vs upgrade' costs was sufficiently high compared to other possible upgrades across our network). We do not consider such high priority upgrades exist now, and as such, if further improvements are required these would need to be undertaken under special-purpose improvement programs, such as the Regional Reliability Improvement program discussed here.[25]

Based on the above, we have determined that the three regions, Eyre Peninsula, Upper North and South East are likely to be the poorest performing regions as we enter the next RCP, and therefore, they are suitable candidate regions for feeder upgrades under the Regional Reliability Improvement Programs.

3.4 Industry practice

We have business-as-usual practices to monitor and report the reliability performance of our network and customer supplies, including identifying LRFs and our worst served customers. These practices include identifying and investigating major outages and recurrent outages causes and upgrading the network if appropriate. We consider these practices are in line with good industry practice and align with the practices of other electricity distribution businesses in Australia and internationally.

Similarly, we consider that the types of network upgrades that we apply and have allowed for in the three separate reliability improvement programs (eg piecemeal upgrade of assets vulnerable to interruption causes, installation of animal guards, upgrade and installation of remote-controlled switchgear and automation) are the current typical best practices approaches for similar circumstances from being in constant contact with our interstate peers and suppliers.

As discussed in Section 5.2, we have considered supply-side, non-network solutions (eg dedicated customer/community generators and/or battery systems), but we do not consider them credible solutions at this stage for the circumstances addressed by this specific program. We have, however, allowed for these types of solutions in the Network Resilience Improvement program, where we consider them to be more appropriate to provide alternative power supplied for major equipment failures and public safety shutoffs.

We intend to continue to monitor the developments and costs of these types of technology to consider whether they will become a more appropriate general solution to similar reliability improvement needs in the future.

3.5 The identified need

While this business case covers three individual program areas associated with the management of reliability on our network via network augmentation capital expenditure (**capex**), they all share common drivers in terms of the identified need that they seek to respond to, being as follows:

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24 For example, there is a colony of bats in the area and possum activity has increased, so we could expect this to cause further decline in animal-related outages.

25 It is worth noting that further upgrade solutions for feeders in this region have been investigated as part of the development and evaluation of the Regional Reliability Improvement program, discussed in Section 5 of this business case. As part of this evaluation, feasible upgrade solutions are developed and tested using the STPIS. This analysis has found that the STPIS will not incentivise further upgrades.

- to respond to customers' concerns,[26] identified through our consumer and stakeholder engagement process, regarding the need to improve reliability service performance for the worst served customers on our network, targeting significant cohorts of customers who are either:
    - supplied from Rural Long Feeders which have supply restoration times greater than the EDC targets;
    - supplied in our worst performing geographic regions; or
    - supplied by feeders that have performance consistently poorer than other feeders in their region (Low Reliability Feeders);
- to respond to customer demand for improved reliability to worst served customers, where this is economically efficient and derives a net benefit for customers – that is, where the economic benefits for customers by way of lower unserved energy (valued in dollar terms using the VCR) outweigh the costs of network expenditure to improve reliability);[27]
- to make efficient and prudent progress toward improving reliability service performance against our jurisdictional regulatory service targets set out in the EDC that we have an obligation to use all reasonable efforts, skills and resources to achieve, that is:
    - for supply restoration times – in order to achieve jurisdictional targets[28];
    - for our reportable geographic regions[29], and
    - for our Low Reliability Feeders[30] - where there is a general expectation that we examine opportunities to improve performance for these feeders; and
- to target network upgrades that while being efficient (on the basis of VCR), are insufficiently incentivised via the STPIS.

As discussed further in section 8, the identified needs of this business case were discussed with our customers, and our customers expect, as reflected in the recommendations of the People's Panel that we invest to improve reliability for worst served customers and achieve the service outcomes proposed in this business case.

[26] This is pursuant to clause 6.5.7(c)(5A) of the National Electricity Rules (NER), which requires regard to be had to the extent to which the forecast capex seeks to address the concerns of distribution service end users identified by the distributor's engagement process.

[27] While there is no explicit NER requirement to improve reliability for worst served customers, the regulatory framework reflected in the NER permits distributors to propose forecast capital expenditure where this is required to 'meet or manage the expected demand for standard control services' pursuant to clause 6.5.7(a)(1) of the NER, where this is efficient pursuant to clause 6.5.7(1), and required to address the concerns expressed by customers through engagement, pursuant to clause 6.5.7(c)(5A).

[28] South Australian Electricity Distribution Code Section 2.2.2 Network restoration standards (pg 8 and pg 9), which require us to use best endeavours (i.e. use all reasonable efforts, skills and resources) to ensure that no more than 30 percent of rural long feeder customers experience an outage longer than 4 hours in duration and no more than 10 percent experience an outage of longer than 7 hours.

[29] Electricity Industry Guideline No.1 Electricity Regulatory Information – Requirements – Distribution Proforma OP 2.8 requires SA Power Networks to report on reliability performance of nine geographic regions and Major Regional Centres. The Commission in its Electricity Distribution Code review – final decision, stated "The Commission's expectation remains that SA Power Networks will manage regional reliability within its overall distribution determination" section 4.2 page 27.

[30] Electricity Industry Guideline No.1 Electricity Regulatory Information – Requirements – Distribution Proforma OP 2.5 requires SA Power Networks to report annually on Low Reliability Feeders, detailing each feeder's reliability performance and what actions have been taken or will be taken to improve reliability performance.

4 Comparison of options

4.1 Program evaluation methodology

We have used a similar methodology and models across all three improvement programs to develop solutions to upgrade feeders and evaluate those upgrades.

4.1.1 Identifying candidate feeders for upgrade

We identified candidate feeders for evaluation based on a technical review of the relevant feeders, their outage history and existing arrangements.

- Low Reliability feeder Improvement Program – We identified 107 feeders across our network for evaluation under this improvement program, using the Long-term Low Reliability Feeder criteria discussed in Section 3.
- Rural Long Feeder Supply Restoration Improvement Program - We identified 370 Rural Long feeders for evaluation under this program. These are the Rural Long feeders that have no remote monitoring of when customers are interrupted, and therefore, we rely on customers contacting us to be notified that supply has been interrupted to these feeders and we need to respond. As there are delays in this manual process, these should be the feeders where we can expect the greatest improvement in the overall Rural Long supply restoration times by installing remote monitoring and control of these feeders.
- Regional Reliability Improvement Program - We identified 80 feeders supplying the three poorest performing regions, discussed in Section 3, for evaluation under this program: 41 feeders supplying the Eyre Peninsula region; 15 feeders supplying the Upper North regions; and 24 feeders supplying the South East region. These are feeders with high customer numbers and/or poor historical reliability. In this way, these should be the feeders where we can expect the greatest improvement in the overall regional reliability through upgrades of these feeders.

Note, each program addressed different feeders and so different worst served customers.

4.1.2 The upgrade solutions considered

We considered various solution types that will provide long-term sustainable improvement in the performance of each feeder considered for upgrade. These solutions reflect the methods we have been applying historically, and so we have confidence in the scale of the improvement that will be realised through these approaches. To support this view, we previously commissioned an independent statistician to validate the expected improvement in supply reliability achieved by the solution types (i.e. solution effectiveness).[31]

The solutions are tailored to address specific recurrent causes of network outages that we can identify in our historical outage data for each feeder. The solution types and the primary outage cause(s) they address are summarised in Table 7 below.

[31] 2015 Reliability Solutions Effectiveness Review Dr A. Kiermeier Statistical Process Improvement Consulting and Training.

Table 7: Mitigation solutions – solutions vs outage causes and effects

Upgrade solution type	Primary outage causes addressed and effect
Re-insulation of lightning prone poor performing line sections with lightning resilient insulators	Reduces outages caused by lightning damaging insulators, and so reduces the likelihood of future outages and resulting customer interruptions.
Installation of covered conductor or undergrounding of bare overhead line sections prone to outages caused by vegetation from outside the prescribed clearance zone	Reduces outages caused by falling vegetation and other wind-blown debris coming into contact with our exposed live equipment, reducing the likelihood of future outages and resulting customer interruptions.
Installation of remotely monitored and controlled switches	Does not reduce the outage causes but reduces the number of customers and line sections that will experience a sustained interruption following a network fault and reduces supply restoration times. Also automatically provides notification of interruptions rather than awaiting customers no supply calls. Allows remote disconnection of supply following a safety incident and allows remote reenergization.
Installing animal guards	Reduces outages caused by animals (eg bats, possums, birds, etc.) by installing a barrier between live and earthed equipment, reducing animals deaths and customer interruptions.

In the case of the Rural Long Feeder Supply Restoration Improvement Program, given the key aim of this program is to improve the average restoration time of rural feeders, the credible upgrade solutions considered involve the upgrade of manually monitored and controlled switches to remote monitoring and control facilities and the installation of additional remote-controlled switches reclosers at new locations for improved network segmentation.

These upgrades will enable automatic identification and reporting of network outages, rather than awaiting customers no supply calls, allowing earlier field crew dispatch, as well as avoiding the time taken to travel to switches to confirm fault targets and restore supply.

4.1.3 Developing the optimal credible solutions for each feeder

To develop an optimal solution for each identified feeder in each of the three improvement programs, we undertook a detailed review of all the outage locations and causes (over the last 7 years) for each feeder. Knowledge gained from this review has been used to define the set of solutions for each feeder and feeder section that would be most appropriate to address the range of recurrent causes of the outages on that feeder.

For each solution identified through this process, we develop:

- the scope of work to implement that solution, based on where these outages have occurred on the feeder;
- the cost of that solution, using our estimate of the number of work units required and unit cost assumptions relevant to the solution types; and
- the expected improvement in supply reliability achieved by the solution (i.e. solution effectiveness).

In this way, for each feeder where we consider some form of improvement will be feasible, we have developed a set of solutions specific to the recurrent outage causes, which we evaluate using cost-benefit analysis techniques.

4.1.4 Non-credible solutions

In appreciating the solutions and options, it is important to note that due to the detailed review that is undertaken to develop individual feasible solutions for each feeder and its specific arrangements and historical performance, we do not develop a range of alternative solutions for each feeder, which can be tested against each other. Instead, each solution (or set of solutions) for that feeder is considered the 'credible' solution(s) for that feeder, given its outage history.[32]

In this solution development process, supply or demand side options such as dedicated, back-up or mobile generation (including customer or community batteries) have been treated as non-credible solutions. This is primarily due to having multiple points of supply for a widespread customer base rather than lines supplying a single large customer base and/or community. Therefore, to install the many supply solutions required at each supply point would be too costly &/or would be unlikely to be able to be enabled quickly enough to provide a sufficient reduction in interruption duration.

To test this view, we estimated the capital cost to employ two alternatives.

1) a Stand-Alone Power System (ie Diesel / Solar / Battery system), and
2) a battery back-up only Stand-Alone Power System.

For these two alternatives, we estimated the capital cost to employ these solutions across a small selection of the feeders upgraded in the Low Reliability Feeder Improvement program, where we had developed feasible network solutions. This sample involved three feeders (a SWER line, an 11kV rural feeder, and an 11kV metro feeder), where the capital costs of the network solution ranged between $285,000 and $500,000 (this compares to the average upgrade cost per feeder across the 67 feeders addressed by this program of $140,000). The alternative solution cost to address the equivalent customers on these feeders ranged between $3 million to $44 million for the Stand-Alone Power System (ie Diesel / Solar / Battery system) and $16 million and $141 million for the battery back-up only Stand-Alone Power System. Although these alternatives would provide additional benefits, given their costs are substantially higher (7 to 25 times) than the network solution, we do not consider these additional benefits would be sufficient to warrant these solutions being considered credible alternatives for our cost-benefit analysis.

These supply-side solutions are, however, being considered within the Network Resilience programs, which are more specifically focused on long-duration interruptions, where major network damage has occurred during extreme weather events (ie major storms, floods, etc.) to whole communities, where these types of solutions can have a much greater benefit in providing an alternative supply at a single supply point, such as at a substation, that supplies many customers to offset very long interruptions to the community and essential services community supplies whilst major network repairs are undertaken.

Using mobile generation as a temporary alternative supply source takes on average 12 hours to be transported to and connected to a single supply point which is longer than the typical interruption duration of the outages addressed through this program.

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[32] This approach is adopted as typically the primary aim of any competing solution is to avoid the impact of the identified outages associated with that feeder ie the benefits are equivalent across potential solutions. Therefore, this detailed review process inherently is aimed at determining the least cost solution to the identified outages. The cost-benefit analysis then tests this solution to determine the benefits and net-benefit of the solution. This more limited approach to identifying the credible solution for an individual feeder also has to be viewed against the typical upgrades allowed for in these programs, which tend to be small low-cost upgrades.

4.1.5 Program Options

Using these feeder-level solutions developed for each program, we considered three program options summarised in Table 8 below. These three options are considered separately for each of the three improvement programs (ie these three options are evaluated for each improvement program).

Table 8: Summary of options considered.

<table>
<tr><th>Option</th><th colspan="2">Description of option</th></tr>
<tr><td></td><td>Low Reliability Feeder Improvement program and Rural Long Feeder Supply Restoration Improvement program</td><td>Regional Reliability Improvement program</td></tr>
<tr><td>The base case – ‘do nothing’</td><td colspan="2">Do nothing
The Improvement program is not undertaken in the next RCP and needs are not addressed.
Note, this option is assumed to be zero cost and zero benefit (in terms of reliability improvement) for comparison against the other upgrade options.</td></tr>
<tr><td colspan="3">Alternative options</td></tr>
<tr><td>Option 1 – Optimal feeder improvement</td><td colspan="2">Optimal feeder improvement
This option allows for the set of solution upgrades on those feeders where we have found a positive net-benefit in implementing the upgrade (ie the set of all solutions that provide positive net-benefit).
This provides the option that addresses needs, but only to the extent that individual feeder upgrades have a net-benefit.</td></tr>
<tr><td>Option 2 – All feeder improvements</td><td>All feeder improvements
This option allows for all upgrade solutions identified (both positive and negative net benefit) for the feeder.
This option provides an alternative to Option 1, which provides a guide to the feasible level of reliability improvement that can be achieved on each feeder.</td><td>Optimal feeder improvement of only Eyre Peninsula and Upper North
This option allows for the set of solution upgrades on those feeders in only the Eyre Peninsula and Upper North regions, where we have found a positive net-benefit in implementing the upgrade (ie the set of all solutions that provide a positive net-benefit).
This option provides an alternative to Option 1 for the Regional Reliability Improvement program, by omitting the improvement of the South East region, which has the most marginal poor performance of the three identified regions (see Section 3.2).</td></tr>
</table>

4.1.6 Option evaluation method and cost and benefit assumptions

We developed separate cost-benefit analysis models for each improvement program. These models have a very similar form and allow us to calculate the costs and benefits of the individual feeder upgrades and aggregate these results to produce the cost and benefits of the three options for each improvement program.

The Reliability Forecasting Structure document provides an overview of the assumptions and their basis that underpin the results presented in this document. The individual cost-benefit analysis models provide a more comprehensive view of individual assumptions associated with the full solution set of each option for each improvement program.

Program costs

The option costs in our cost-benefit analysis only include those capital costs associated with the assets that will form the upgrade. The option costs do not include operating costs or any offset for avoided costs. There is some small amount of offset to operating supply restorations costs ($120k pa) through outages avoided through the improvement programs and opex adjustments have been calculated for the next RCP. Although these offsets have not been included in the cost-benefit analysis of individual solutions, the overall adjustment for the whole program is provided as opex reduction adjustment to our opex forecasts (see Section 6).

The option cost is calculated as the aggregate of the set of solution costs associated with each option. These individual solution costs are calculated from the estimated volume of units (developed from the detailed review of the outages of that feeder and the feasible solutions) and a schedule of assumed unit costs for each solution type. This schedule of unit costs has been developed based on the historical cost of undertaking equivalent upgrades.

Program quantified benefits

The quantified benefits (in $ terms) of all program options only includes the value of the estimated improved reliability. This value represents the total value of the improved reliability provided by the option, which is calculated as the aggregate value provided by the set of upgrade solutions associated with each option. The individual solution value is calculated based on:

- the assumed customer minutes improved by that solution, if the solution was applied on recent historical outages and the assumed probability of improvements provided by that solution type[33];
- the average avoided unsupplied energy amount using a feeder-level kwh per customer minute for that feeder, which is calculated based on the customer types associated with that feeder and their average energy usage; and
- the VCR for that feeder, which is based on 2022 customer-type VCRs published by the AER and the number of customers in that type for that feeder, as determined from our data systems.

Program Non-quantified benefits

Material benefits of the improvement program options not quantified in the cost-benefit analysis could include:

- avoided operating and maintenance costs associated with replaced assets; and
- avoided guaranteed service level payments (**GSL**) payments associated with avoided interruptions that have resulted in GSL payments.

[33] Estimated from statistical analysis of the effectiveness of this solution type based on its historical use.

These non-quantified benefits have been assumed to be too small, compared to the benefit of reliability improvement, to warrant their estimation for the evaluation of individual solutions. However, their significance is discussed further in Section 6 below, when we discuss the regulatory treatment of the program within our proposal.

We have not attempted to quantify the benefits of these programs in terms of mitigating the predicted effects of climate change. In this regard, a primary objective of these programs is *not* to make the network more resilient to extreme weather events and the effects of future climate change on the frequency and severity of these events, and we have *not* allowed for the effects of future climate change in our analysis.

Nonetheless, an overarching objective of the three improvement programs is to mitigate persistent issues and escalating causes that contribute to the poor reliability experienced by customers, most of which is due to weather. As such, these programs provide some support to addressing our customers concerns expressed during our engagement on the resilience of the network, whereby they should address the root causes of some outages and mitigate the effects of others, improving the resilience of supply services to our worst served customers.

We also have a special-purpose program (not included in this business case) aimed at improving the resilience of customer supplies to extreme weather events (the Network Resilience program). However, unlike the reliability improvement programs in this business case which focus on addressing the root causes of historical outages, the Network Resilience program is focused on providing alternate power supply support to major community centers to restore basic essential services to customers during very long-duration supply interruptions, which can occur when significate equipment damage has resulted from extreme weather events.

4.2 Analysis summary and recommended option

4.2.1 Low Reliability Feeder Improvement Program

Option evaluation results

Table 9 summarises the results of our cost-benefit analysis of the three options discussed above, and Table 10 summarises the improvement in reliability achieved by these options.

Table 9: Costs, benefits, and risks of alternative options ($ millions). Benefit and NPV are over life of upgrade.

Option	Costs		Benefits	NPV	Ranking
	Capex	Opex	Reliability Improvement		
Option 0 – do nothing	-	-	-	0	3
Option 1 - Optimal feeder improvements	9.1	0.0	38.2	15.2	1
Option 2 – All feeder improvements	11.7	0.0	40.5	14.4	2

Table 10: Customer service improvement of options (includes MEDs)

Option	Feeders improved	Customers improved	Average feeder USAIDI improved (mins)	Average feeder USAIDI improved (%)
Option 0 – do nothing	0	0	0	0%
Option 1 - Optimal feeder improvements	67	35,360	143	31%
Option 2 – All feeder improvements	81	41,483	135	28%

Recommended option

Our recommended option is Option 1: the optimal feeder improvement, which comprises the set of solution upgrades on those Long-Term Low Reliability Feeders where we have found a positive net-benefit in implementing the upgrade (i.e., the set of all solutions that provide a positive net-benefit).

The $9.6 million capital cost of this option will allow us to continue the current program to enable the upgrade of a further 58 Long-Term Low Reliability Feeders in the next RCP, including upstream feeders that supply LT LRFs. The upgrade of each of these feeders has been found to provide a positive net-benefit by our LRF CBA model.

This option is the least cost option (other than ‘do nothing’) and ranks first in terms of the net-benefit. This option will improve reliability of supply to 13,904 Low Reliability customers and a total of 35,360 customers by an average of 143 SAIDI minutes[34].

We have selected this as our preferred option as it:

- addresses the identified needs discussed in Section 4;
- represents a low-risk solution in terms of its implementation as it represents relatively simple upgrades to existing systems that we have applied during the current and past RCPs; and
- strikes the right balance between the preferences of our customers to improve supplies to our worst served customers and limit price increases.

Based on the review of these options and cost-benefit results (both from a bottom-up review by relevant internal subject matter experts and the top-down challenge applied across our proposal forecasts), we have rejected the other options primarily for the reasons set out below.

Option 0 (do nothing)

This is the least cost option, but it does not address the identified need noting that:

- it will not address the declining performance experienced by these worst served customers, and would also increase the likelihood that the number of Low Reliability Feeders and worst served customers will increase over the next RCP; and
- it would therefore not provide an improved service outcome that our customers have recommended in our engagement, as it takes no action towards improving reliability for customers on our low reliability feeders and therefore also does not derive any economic net benefit for consumers in terms of supply reliability improvement.

34 Note, a total of 35,360 customers will benefit from this program, as the upgrade of some feeders upstream of the LTLRF are included in the program. The upgrade of these upstream feeders were found to be the best solution to improve supply to the relevant downstream LTLRFs through the detailed technical review of that LTLRF.

We do not consider that this option aligns with our customer and stakeholder preferences, particularly given that other credible options have appreciable net-benefits in terms of supply reliability improvement.

Option 2 (all feeder improvements)

Option 2 provides the greatest improvement in supply reliability, upgrading 81 Long-Term Low Reliability Feeders and improving supplies to 41,483 of our worst served customers by on average 135 minutes.

However, this option has a higher capital cost compared to the recommended option, at an additional $2.6 million (29% higher), and provides a lower net-benefit ($0.9 million less net-benefit over the life of the upgrades).

Recommended option scope and costs

Table 11 provides a summary of the scope of works for the recommended option, which was developed through the detailed review of Long-Term Low Reliability Feeder outages discussed above[35]. For comparison purposes, this table also shows the equivalent scope for Option 2 (ie all feeder solutions).

Table 11: Summary of option scope of works

		Option 1 (recommended)			Option 2		
Solution Type	**Solution Detail**	**Projects**	**Solution Units**	**Total Cost**	**Projects**	**Solution Units**	**Total Cost**
Animal Guards	Animal guard installation - Spot	2	2	$5,834	6	6	$17,502
Insulator upgrades	Insulator Upgrade - SWER	26	1,604	$1,738,424	33	1,910	$2,070,069
	Insulator Upgrade - 11kV Pins	4	225	$623,142	5	256	$708,997
	Insulator Upgrade - 33kV	2	405	$1,541,529	2	404	$1,537,723
Conductor Insulation	IUC per span	2	21	$484,666	2	21	$484,666
	Line Covering	1	2	$11,213	1	2	$11,213
Switches							
	Fuse Saver (On SCADA)	6	6	$221,562	10	10	$369,269
	Mid Line Reclosers with CB upgrade	28	28	$2,778,752	36	36	$3,572,681
	Remote LS switch	16	16	$960,100	31	31	$1,860,195
	SWER Sectionliser	15	15	$152,324	22	23	$233,563
	SWER Recloser (Hydraulic)	5	5	$92,317	7	7	$129,244
	UD Switch Automated	2	2	$461,587	3	3	$692,380
	Total	**109**	**2,331**	**$9,071,450**	**158**	**2,709**	**$11,687,502**

[35] The number of 'projects' in this table can be considered as the number of individual solutions of that type, which were developed and the net-benefit individually evaluated across the set of LTLRF. The units can be considered the quantity of that solution type included in those projects eg for the 'Underground HV & LV' solution type, the single project allows for the undergrounding of 6km of line.

Scenario and sensitivity analysis

Sensitively analysis has been carried out on the discount rate applied to the Lower Reliability Feeders program for the recommended Option 1: the optimal feeder improvement, with results tabled below.

Table 12: Option 1: optimal feeder improvement - discount rate sensitivity analysis over life of assets

Low Reliability Feeders	PV Cost ($M)	PV Benefit ($M)	NPV ($M)
Discount Rate - Reduction 3.5%	$8.33	$24.94	$16.60
Discount Rate - Current 4.05%	$8.23	$23.47	$15.24
Discount Rate - Increase 4.5%	$8.14	$22.36	$14.22

4.2.2 Rural Long Feeder Supply Restoration Improvement program

Option evaluation results

Table 13 summarises the results of our cost-benefit analysis of the three options, Table 14 summarises the improvement in the average supply restoration time, Customer average interruption duration index (**CAIDI**), for the Rural Long feeder category achieved by these options. Table 15 shows our estimated average performance against the current EDC supply restoration time targets over the next RCP for the three options[36].

Table 13: Costs, benefits and risks of alternative options ($ millions). Benefit and NPV are over life of upgrade.

Option	Costs		Benefits	NPV	Ranking
	Capex	Opex	Reliability Improvement		
Option 0 – do nothing	-	-	-	-	3
Option 1 - Optimal feeder improvement	4.3	0.00	14.1	5.8	1
Option 2 – Feasible feeder improvement	17.4	0.00	23.0	0.1	2

Table 14: Aggregate improvement to supply restoration time achieved by the three options

			CAIDI[37] improvement		
Option	Feeders improved	Customers improved	Current Average CAIDI (mins)	Average CAIDI reduction after Improvement	Av CAIDI Improvement (%)
Option 0 – do nothing	-	-	-	-	-
Option 1 - Optimal feeder improvement	44	10,230	484	74	15%
Option 2 – Feasible feeder improvement	183	33,352	445	41	6%

[36] Note, this is our estimate assuming average annual weather condition, and so can be considered our estimate of the movement from the projected linear trends shown in Section 3.2.

[37] CAIDI is the Customer Average Interruption Duration Index, which can be viewed as a measure of the average supply restoration time observed by that cohort of customers across all interruptions of those customers

Table 15: Expected percentage of customer exceeding target by three options – for average conditions.

	% customer exceeding 4-hour target		**% customer exceeding 7-hour target**	
Option	Current target	Estimate average over next RCP	Current target	Estimate average over next RCP
Option 0 – do nothing	30	35.4	10	11.5
Option 1 - Optimal feeder improvement	30	30	10	10
Option 2 – Feasible feeder improvement	30	28	10	9

Recommended option

Our recommended option is Option 1: the optimal feeder improvement, which includes the set of solution upgrades on those Rural Long feeders where we have found a positive net-benefit in implementing the upgrade (ie the set of all solutions that provide a positive net-benefit).

The $4.3 million capital cost of this option will allow us to upgrade 44 Rural Long feeders in the next RCP. The upgrade of each of these feeders will provide a net-benefit as calculated in our Rural Long Supply Restoration CBA model.

This option is the least cost option (other than 'do nothing') and ranks first in terms of the net-benefit, materially improving supply restoration times (CAIDI) to 10,230 customers by an average of 74 minutes.

We have recommended this option as it:

- addresses the identified needs discussed in Section 4;
- represents a low-risk solution in terms of its implementation as it represents relatively simple upgrades to existing systems that we have experience of applying; and
- strikes the right balance between the preferences of our customers to improve supply restoration times to our worst served customers whilst limiting price increases.

Based on the review of these options and cost-benefit results (both from a bottom-up review by relevant internal subject matter experts and the top-down challenge applied across our proposal forecasts), we have rejected the other options primarily for the following reasons:

Option 0 (do nothing)

This is the least cost option, but it does not address the identified needs. Importantly, this option would mean that:

- we would continue to exceed the EDC supply restoration targets in every year over the next RCP unless there are relatively benign conditions that year; and
- we would not provide a service outcome that our customers have recommended through our engagement program as it would take no action in addressing poor supply restoration times, and therefore also does not derive any economic net benefit for consumers in terms of reliability improvement.

Option 2 (feasible feeder improvements)

Option 2 improves restoration times to more customers by upgrading 183 Rural Long feeders and improving restoration times to 33,352 of our worst served customers by on average 41 minutes.

However, this option has a higher capital cost, at an additional $13.1 million compared to the recommended option (Option 1) and provides a net-benefit which is $5.73 million less over the life of the upgrades than the recommended option.

Recommended option scope and costs

Table 16 provides a summary of the scope of works for the recommended option, which was developed through the detailed review discussed above. For comparison purposes, this table also shows the equivalent scope for Option 2 (ie all feasible solutions).

Table 16: Summary of option scope of works

	Option 1 (Recommended)			Option 2	
Solution Type	**Solution Units**	**Cost**		**Solution Units**	**Cost**
11kV recloser on SCADA	17	$1,702,793		22	$2,203,615
Mid Line Reclosers with CB upgrade	5	$496,206		11	$1,091,653
Remote LS switch	9	$540,056		23	$1,380,144
SWER Mid Line Switch on SCADA	27	$1,171,507		251	$10,890,678
SWER Source recloser on SCADA	2	$138,476		23	$1,592,474
Mid Line Recloser on SCADA	4	$276,952		4	$276,952
Grand Total	**64**	**$4,325,991**		**334**	**$17,435,516**

a - The total feeder number is the number of feeders addressed by the option, which may not equal the sum of feeders by solution type, as some feeders will have multiple solutions to upgrade the feeder

Scenario and sensitivity analysis

Table 17 shows the results of the sensitivity analysis that was conducted on the discount rate applied to the Rural Long Supply Restoration Improvement program for the recommended Option 1: the optimal feeder improvement.

Table 17: Option 1: optimal feeder improvement – discount rate sensitivity analysis

Supply Restoration - Rural Long	PV Cost ($M)	PV Benefit ($M)	NPV ($M)
Discount Rate - Reduction 3.5%	$3.97	$10.19	$6.21
Discount Rate - Current 4.05%	$3.92	$9.72	$5.79
Discount Rate - Increase 4.5%	$3.88	$9.35	$5.47

4.2.3 Regional Reliability Improvement program

Option evaluation results

Table 18 summarises the results of our cost-benefit analysis of the three options. Table 19 shows the breakdown of the costs and benefits by region. Table 20 shows the reliability improvements achieved in each region (both tables also indicate whether or not the region is included in the three options).

Table 18: Regional Reliability Improvement program cost-benefit analysis

Option	Costs		Benefits	NPV	Ranking
	Capex	Opex	Reliability Improvement		
Option 0 – do nothing	-	-	-	-	3
Option 1 – Optimal feeder improvement of three regions	$13.7	$-	$82.71	$37.19	1
Option 2 – Optimal feeder improvement of only Eyre Peninsula and Upper North	$9.42	$-	$71.14	$34.13	2

Costs, benefits and risks of alternative options relative to the base case over the X-year period, $m, $ Dec 2022 real. The Option 0 (Base Case) costs have been subtracted from all options Costs, benefits and risks of alternative options ($ millions). Benefit and NPV are over life of upgrade.

Table 19: Costs and benefits by region.

Region	Option Included			Costs		Benefits	NPV
	Option 0	Option 1	Option 2	Capex	Opex	Reliability Improvement	
Eyre Peninsula		✓	✓	$5.16	$-	$54.44	$27.54
Upper North		✓	✓	$4.01	$-	$16.70	$6.82
South East		✓		$4.28	$-	$11.56	$3.06

Table 20: Customers and Reliability improvements by region.

Region	Option Included			Feeders	Customers	USAIDI (ex MED) (mins)	USAIDI (ex MED) (%)	USAIFI (ex MED) (mins)	USAIFI (ex MED) (%)
	Option 0	Option 1	Option 2						
Eyre Peninsula		✓	✓	22	6,176	46	10%	0.14	10%
Upper North		✓	✓	13	10,819	37	10%	0.09	5%
South East		✓		17	6,535	15	5%	0.10	6%

Recommended option

Our recommended option is Option 1: optimal feeder improvement of three regions, which includes the set of solution upgrades on the identified feeders in each region where we have found a positive net-benefit in implementing the upgrade (ie the set of all solutions that provide a positive net-benefit). The $13.7 million capital cost of this option will allow us to upgrade 52 feeders in the next RCP, 22 in the Eyre Peninsula, 13 in the Upper North and 17 in the South East. The upgrade of each of these feeders has been found to provide a positive net-benefit by our Regional Reliability CBA models.

This option is a higher cost option than Option 2 (and the ‘do nothing’ option) but has the greatest benefits ($82.71 million over the life of the upgrades) and the greatest net-benefits ($37.19 million over the life of the upgrades). This option improves reliability to 23,530 customers across the three regions, covering:

- 6,176 customers in the Eyre Peninsula, resulting in a regional improvement of 10% in SAIDI (ex MEDs) and 10% in SAIFI (ex MEDs);
- 10,819 customers in the Upper North, resulting in a regional improvement of 10% in SAIDI (ex MEDs) and 5% in SAIFI (ex MEDs); and

- 6,535 customers in the South East, resulting in a regional improvement of 5% in SAIDI (ex MEDs) and 6% in SAIFI (ex MEDs).

This option is recommended as it:

- addresses the identified needs discussed in Section 4;
- represents a low-risk solution in terms of its implementation as it represents relatively simple upgrades to existing systems that we have experience of applying; and
- strikes the right balance between the preferences of our customers to improve supplies to our worst served regions and limit price increases.

Based on the review of these options and cost-benefit results (both from a bottom-up review by relevant internal subject matter experts and the top-down challenge applied across our proposal forecasts), we have rejected the other options primarily for the reasons set out below.

Option 0 (do nothing)

This is the least cost option, but it does not address the identified needs, noting that:

- It increases the likelihood that the reliability of the three poorest performing regions within our network could degrade further over the next RCP; and
- It does not provide a service outcome that our customers recommended IN our engagement program as it would take no action in addressing reliability of our worst served regions/customers, and therefore also does not derive any economic net benefit for consumers in terms of reliability improvement.

Option 2 (Optimal feeder improvement of only Eyre Peninsula and Upper North)

Option 2, which omits the upgrades to the South East region, is a lower cost option, but has a lower benefit and net-benefit to the recommended option.

Table 19 above shows that the South East region has the lowest benefit to cost ratio of the three regions. Furthermore, as noted in Section 3.2, the South East has already seen some improvement in the last two years, which is likely partly due to recent upgrades we have undertaken in this region, but the extent to how much this has corrected the poor performance is uncertain at this time. Therefore, given its lower net-benefit to Option 1, we have not recommended this option.

Recommended option scope and costs

Tables 21 to 23 provide a summary of the scope of works for the three regions, which was developed through the detailed review discussed above[38].

[38] The total feeder number is the number of feeders in each region, which may not equal the sum of feeders by solution type, as some feeders will have multiple solutions to upgrade that feeder.

Table 21: Summary of option scope of works – Eyre Peninsula (Option 1 and 2)

Solution types	Solution - detail	feeders	projects	units	capex ($'000)
re-insulation	Insulator Upgrade - 33kV	1	1	794	3,022.2
re-insulation	Insulator Upgrade - SWER	10	11	794	860.5
switches	11kV Recloser on SCADA	6	8	8	801.3
switches	Mid Line Reclosers with CB upgrade	3	3	3	297.7
switches	Remote LS switch	5	5	5	300.0
switches	SWER Mid Line Switch on SCADA	2	2	2	86.8
switches	Fuse Saver (On SCADA)	1	1	1	36.9
Total		**28**	**31**	**1,607**	**5,405.5**

Table 22: Summary of option scope of works – Upper North (Option 1 and 2)

Solution types	Solution - detail	feeders	projects	units	capex ($'000)
re-insulation	Insulator Upgrade - 33kV	3	3	580	2,207.6
re-insulation	Insulator Upgrade - SWER	2	2	200	216.8
switches	Mid Line Reclosers with CB upgrade	3	3	3	297.7
switches	11kV Recloser on SCADA	1	2	2	200.3
switches	33kV LS installation on SCADA	2	3	3	180.0
switches	Mid Line Recloser on SCADA	1	1	1	69.2
switches	Remote LS switch	1	1	1	60.0
switches	SWER Mid Line Switch on SCADA	1	1	1	43.4
covered conductor and undergrounding	Underground High Voltage & Low Voltage	1	1	8	738.5
Total		**15**	**17**	**799**	**4,013.6**

Table 23: Summary of option scope of works – South East (Option 1 only)

Solution types	Solution - detail	feeders	projects	units	capex ($'000)
re-insulation	Insulator Upgrade - 11kV Pins	6	7	313	902.9
switches	2x 33kV TF Breakers + 1x 11kv Section Breaker	1	1	1	1384.8
switches	11kV Recloser on SCADA	7	10	10	1001.6
switches	Remote LS switch	6	6	6	360.0
switches	Fuse Saver (On SCADA)	3	4	4	147.7
covered conductor and undergrounding	IUC per span	3	4	21	484.7
Total		**26**	**32**	**355**	**4,281.7**

Scenario and sensitivity analysis

Sensitively analysis was undertaken on the discount rate applied to the Regional Improvement programs for the recommended Option 1: the optimal feeder improvement, with results tabled below.

Table 24: optimal feeder improvement – sensitivity analysis

Regional Improvement Eyre	PV Cost ($M)	PV Benefit ($M)	NPV ($M)
Discount Rate - Reduction 3.5%	$4.74	$34.40	$29.65
Discount Rate - Current 4.05%	$4.68	$32.22	$27.54
Discount Rate - Increase 4.5%	$4.63	$30.58	$25.95
Regional Improvement Upper Nth	**PV Cost ($M)**	**PV Benefit ($M)**	**NPV ($M)**
Discount Rate - Reduction 3.5%	$3.69	$11.09	$7.40
Discount Rate - Current 4.05%	$3.64	$10.46	$6.82
Discount Rate - Increase 4.5%	$3.60	$9.98	$6.37
Regional Improvement South East	**PV Cost ($M)**	**PV Benefit ($M)**	**NPV ($M)**
Discount Rate - Reduction 3.5%	$3.93	$7.40	$3.47
Discount Rate - Current 4.05%	$3.88	$6.94	$3.06
Discount Rate - Increase 4.5%	$3.84	$6.60	$2.76

5 Treatment in our regulatory proposal

5.1 Relationship to other reliability improvement programs

As discussed previously, the three improvement programs in this business case target different feeders, and so, different worst served customers. Therefore, there is no double counting of the reliability improvement between these three programs.

Tables 25 and 26 show the SAIDI improvement to the regional average SAIDI expected to be achieved by the three reliability improvement programs covered by this business case over the next RCP. The STPIS target adjustments will occur incrementally over the next five-year RCP as the program is rolled out over this period.

Table 25: Regional reliability improvements achieved by the reliability and resilience improvement programs (Including MED)

ESCoSA Region SAIDI Improvement Include. MED	2025-30 RI Eyre	23-30 RI South East	25-30 RI Upper Nth RI	2025-2030 RI Low Reliability	2025-2030 RL Supply Restoration	Grand Total
Barossa, Mid-North, Yorke Peninsula				5	3	8
Eastern Hills				11	6	17
Eyre Peninsula	57			22	10	88
Fleurieu Peninsula				4	1	4
Adelaide Metropolitan Area				1		1
Rural Metropolitan Centres				0		0
Riverlands and Murraylands				7	3	10
South East		20		16	11	47
Upper North			146	13	6	165

Table 26: Regional reliability improvements achieved by the reliability and resilience improvement programs (Excluding MED)

Sum of ESCoSA Region SAIDI Saved Underlying Excluding MED	2025-30 RI Eyre	23-30 RI South East	25-30 RI Upper Nth RI	2025-2030 RI Low Reliability	2025-2030 RL Supply Restoration	Grand Total
Barossa, Mid-North, Yorke Peninsula				4	1	6
Eastern Hills				6	2	8
Eyre Peninsula	46			17	9	71
Fleurieu Peninsula				4	0	4
Adelaide Metropolitan Area				0		0
Rural Metropolitan Centres				0		0
Riverlands and Murraylands				4	2	5
South East		15		14	7	35
Upper North			37	13	3	54

a – the CBD reliability Improvement program is a separate improvement program discussed in its own business case (Document 5.9.4). So it has been excluded in this table. For the avoidance of doubt, none of the three reliability improvement programs discussed in this business case relate to the CBD network.

5.2 Relationship with other components of our capex forecasts

There is limited scope for duplication between the reliability management programs and other components of our capex forecasts. Nonetheless, as discussed in the Reliability Augex Forecasting Structure document, we have implemented various processes to ensure that interrelationships are identified and allowed for.

5.2.1 Interaction with the repex forecast

There is limited scope for duplication between the reliability improvement programs and the repex programs as they address different aspects of supply reliability as:

- Overall network interruptions impacting customers within this program contributing causes are:
  - 72% Third party causes impacting our Assets (Lightning, Vegetation, animals etc.)
  - 28% Asset condition failures
- Rather than asset replacement our Network Reliability Improvement programs focuses on
  - modifying existing assets, such as installing covers on existing assets, to reduce interruptions caused by third party causes;
  - installing additional new switches at new locations to reduce customers interrupted; and
  - a portion of the Network Reliability Improvement programs spend is on replacing and upgrading the following existing assets:
    - upgrading 1.7% of existing Reclosers to modern remote controlled devices to improve supply restoration times – these reclosers will still require cyclic maintenance (repex);
    - upgrading 0.004% of our overhead bare conductor to insulated conductor;
    - upgrading 0.8% of our insulators to lightning resistant insulators.

These Asset upgrades are again primarily to reduce interruptions caused by third-party causes & to improve supply restoration times, and are not driven by the age/condition of assets, the small amount of existing assets to be upgraded are unlikely to be targeted for Repex as:

- existing porcelain insulators to be upgraded to reduce lightning outages do not deteriorate; and

- bare conductors to be upgraded to insulated conductors to reduce vegetation outages are in Non Bushfire, low corrosion areas and do not have a history of conductor failures through condition.

Switches to be upgraded to remote control to improve supply restoration times, will still require ongoing cyclic Repex to ensure they are operational.

The impact of Network Reliability Improvement programs to the repex program is considered immaterial in that:

- they aim to address different outage causes,
- where the replacement programs are focused on addressing outage causes due to asset failures driven by the age/condition of assets and the reliability improvement programs address other outage causes;
- the objectives of the programs on reliability differ, where the repex program primarily is aiming to maintain the reliability risk as the assets continue to age through the next RCP and the reliability improvement programs are addressing existing (non-asset age/condition) factors causing poor reliability; and
- these Assets are not likely to be addressed in the repex program as they do not have a history of asset condition failures.

It is possible that some form of enhanced (or accelerated) replacement program could be used as an alternative to the reliability improvement programs. However, if 100% of assets where replaced it would still only address 28% of outage causes and typically be found to be a far more costly solution in most circumstances, as it typically requires more extensive early replacements along a feeder than is necessary to achieve a lesser reliability improvement. For example, we assessed a selection of the identified feeder upgrades in our Low Reliability Feeder Improvement program and found an enhanced replacement alternative to be in the order of 6 to 7 times more costly solution in terms of the capital cost per customer minute improved.[39]

That said, the various reliability management improvement programs have elements of asset replacement, but only in circumstances where there is a need for enhanced service provided by upgrading the asset with improved functionality – not replacing like for like (e.g., replacing a manual switch with a remote-controlled switch or replacing bare overhead conductor with insulated conductor).

This still provides the possibility for duplication between programs in circumstances where the replacement program allows for the replacement of these existing assets, however, this has been calculated as not material enough to consider adjustment with the repex forecast.

5.2.2 Interaction with the Network Resilience program

As discussed in Section 4, we have a Network Resilience Improvement program, which is primarily aimed at improving the resilience of supply services during extreme weather events. However, there is limited scope for duplication between the reliability improvement programs and Resilience Improvement program as they focus on addressing different outage types, where the three reliability improvement programs covered in this business case focus on addressing the root causes of recent historical outages, whereas the Network Resilience Improvement program is focused on providing non network alternative supply solutions

[39] For this analysis, we tested 6 feeders upgraded in the Low Reliability Feeder Improvement program, where we had developed feasible network solutions. The feeders selected represented those where asset failures contributed 60% or more to the total feeder customer minutes interrupted. For these feeders, we estimated the replacement costs necessary to address the equivalent outages, which mainly consisted of replacing sections of conductor/cable, pole tops and crossarms, and transformers. The capital costs of the network solution ranged between $30,000 and $265,000 (this compares to the average upgrade cost per feeder across the 67 feeders addressed by this program of $140,000). The enhanced replacement alternative ranged between $285,000 and $18 million, suggesting solution cost 4 to 73 times higher.

specifically related to when significant equipment damage has occurred resulting in a long duration outages or when disconnection is required for public safety during fire danger conditions. A detailed technical review was conducted across the historical outages to identify the outages relevant to the three reliability improvement programs and those relevant to the Network Resilience Improvement program, no historical interruptions addressed by the three reliability improvement programs would be mitigated by the proposed Network Resilience Improvement program.

Furthermore, there is no scope for duplication of solution, as the recommended solution for the Network Resilience Improvement program is the purchase of additional mobile generation units. However, as discussed in Section 5 on non-credible solutions, we do not consider that this solution is a credible solution for mitigating the outages addressed by the three reliability improvement programs, which typically have durations too short for mobile generation to be transported and connected in time to significantly reduce the interruption duration.

5.2.3 Interaction with the Bushfire Risk Mitigation Program

A cross check has been undertaken to ensure reclosers targeted for upgrades as part of these programs have not been identified for upgrades as part of the proposed Bushfire Risk Mitigation Program.

5.3 Implications on STPIS settings

We included the full capital costs for the recommended options for all three improvement programs in our capex forecast for the next RCP. These three programs only include network solutions where we do not expect the STPIS to provide sufficient incentive to undertake the upgrade[40].

Nonetheless, we still anticipate that the three improvement programs will produce a modest improvement to the underlying reliability measured through the STPIS. Therefore, rather than adjusting the capex forecast for these programs to allow for this, we have included the downward adjustments to the STPIS targets for the next RCP as shown in Tables 27 and 28.

Table 27: Adjustments to STPIS targets due to the three-reliability improvement programs (SAIDI)

SAIDI Reduction (Minutes)	Rural Long	Rural Short	Urban	Network
Feeder Cat Customer Base (July 2023)	138,895	140,928	644,627	931,333
Low Reliability Feeders	9.6	1.7	0.3	1.9
Regional	10.6	1.1	0.0	1.7
Rural Long Supply Restoration	4.3	0.0	0.0	0.6
Grand Total	**24.5**	**2.8**	**0.3**	**4.4**

[40] This can occur for various reasons, primarily in situations where the customer density associated with the upgrade is low compared to the average for that network type. However, it can also occur where the solution is more greatly focused on improving CAIDI rather than SAIFI or where a material portion of the avoided customers minutes are associated with MEDs.

Table 28: Adjustments to STPIS targets due to the three-reliability improvement programs (SAIFI)

SAIFI Reduction (Interruptions)	Rural Long	Rural Short	Urban	Network
Feeder Cat Customer Base (July 2023)	138,895	140,928	644,627	931,333
Low Reliability Feeders	0.03	0.01	0.00	0.01
Regional	0.04	0.01		0.01
Rural Long Supply Restoration	0.02			0.00
Grand Total	**0.09**	**0.01**	**0.00**	**0.02**

a – the CBD reliability Improvement program is a separate improvement program discussed in its own business case. So impact has been excluded in this table. For the avoidance of doubt, none of the three reliability improvement programs discussed in this business case relate to the CBD network.

It is important to note that the STPIS target adjustments will occur incrementally over the next five-year RCP as the program is rolled out over this period.

5.4 Implications on other costs

As discussed in Section 5, we have not quantified offsetting capex-opex trade-offs in our cost-benefit analysis of the solution components that together form the individual improvement programs. However, we do expect that in aggregate the Low Reliability Feeder Improvement and Regional Reliability Improvement programs should provide a small overall reduction in the current recurrent level of opex, due to a reduction in network interruptions and associated reduced emergency response costs achieved by the programs.

To allow for this capex-opex trade off, we are proposing the following negative step changes to our opex forecast to allow for each of these programs:

- Low Reliability Feeder Improvement program - $0.06 million per annum
- Regional Reliability Improvement program - $0.06 million per annum.

The changes in opex due to the implementation of the program will occur incrementally over the next five-year regulatory period as the program is rolled out over this period.

In the case of the Rural Long feeder Supply Restoration Improvement program, we do not consider that this program would result in a material overall reduction in opex as outage causes are not being mitigated. That is, any minor reduction in the operating costs associated with reducing on site outage attendance times would be offset by the increased opex associated with the additional operating and maintenance costs associated with the upgraded electronic assets.

6 Deliverability of recommended option

We have developed a plan to ensure that it can deliver these worst served customer reliability improvement programs together among all the increased volume of work reflected in the programs that comprise our total network expenditure forecast in our Regulatory Proposal. This plan considers the detailed implications of our proposed overall uplift in total network expenditure for our required workforce and supporting internal services of information technology, feet, property and human resources.

We consider that our plan is realistic and achievable over the 2025-30 RCP. The details of our approach are set out in our accompanying document, '5.2.5 - Resourcing Plan for Delivering the Network Program'.

7 How the recommended option aligns with our consumer and stakeholder engagement.

The service outcomes that are enabled by the expenditure and programs proposed in this business case, are aligned to achieve outcomes that were directly supported by our customers as ultimately reflected in the recommendations of the People's Panel. This is noting that:

- the topic of service reliability has been a key focus of our consumer and stakeholder engagement program. One of the four key themes that have framed our engagement under a desire to 'focus on what matters' to our customers has been the theme of 'a reliable, resilient, and safe electricity network';
- in engaging on this theme, and under the specific topic of 'reliability and bushfire safety' we undertook a series of deep-dive workshops called 'Focused Conversations' with a broad range of consumer, industry, government and regulatory body representatives. In these Focused Conversations we sought recommendations on the service outcomes that customers prefer and expect;[41]
- with particular regard to the Worst Served Customers Reliability Improvement Programs covered in this business case, we engaged on the identified needs by outlining data on our reliability and supply restoration performance on a feeder, regional, and overall network basis, our expenditure in this area and reasons explaining this performance and risks forecast over the 2025-30 RCP;
- we then posed three scenarios of how we could respond to the needs, and the expected outcomes for customers in relation to service, expenditure and price – these included (1) doing nothing (2) spending to maintain underlying reliability only (3) spend more to not only maintain underlying reliability but also improve reliability for worst served regions and customers across the three areas covered in this business case (regions, low reliability feeders, rural supply restoration);[42]
- while our customers and stakeholders were consistently mindful of energy affordability concerns, the Focused Conversation arrived at a clear consensus recommendation to the People's Panel as the next stage in our engagement program, that we should invest sufficiently in order to maintain reliability and that it should also seek to improve reliability for worst served regions and customers - the latter outcomes being the subject of this Worst Served Customers Reliability Improvement Programs business case; and
- ultimately, the People's Panel deliberated on and affirmed the results of the Focused Conversations in their formal recommendation,[43] and we have committed to taking this recommendation forward as reflected in the recommendations contained in this business case.

Since conducting the People's Panel process, we published a Draft Proposal to play back how we have given effect to customer recommendations and to confirm that those recommendations remain valid given continued cost of living pressures and to obtain further input to refine our Regulatory Proposal. Submissions received on our Draft Proposal suggest that the recommendations of the People's Panel remain valid with

41 This was covered in workshops 1, 3 and 4 for the Reliability and bushfire safety Focused Conversation. Materials presented at the Focused Conversations are available on our TalkingPower website under the page titled 'focused conversations'. [https://www.talkingpower.com.au].

42 The recommendations of the Focused Conversation are contained in documents published on our TalkingPower website under the page titled 'focused conversations'. SAPN, *final outputs and recommendations to the People's Panel for Reliability and Bushfire Safety*, October, 2023. Accessible on: [https://www.talkingpower.com.au].

43 The recommendations of the People's Panel are contained in documents published on our TalkingPower website under the page titled 'people's panel'. SAPN, *SA Power Networks People's Panel Final Report – Balancing service and price*, March 2023.

respect to the Worst Served Customers Reliability Improvement Programs outlined in this business case, noting that:

- members of the People's Panel affirmed that their recommendations, including in respect of property expenditure as set out in this business case, remain current;[44]
- some parties such as that from SACOSS[45] and the Department of Energy and Mining [46] generally urged further consideraiton of the overall magnitude of our forecat capital expenditure across in totality. However, at the same time, DEM noted specifically that it supports the targeted improvements in regional reliability covered in this business case.
- SACOSS did not support expenditure to improve regional reliability above current levels of reliability, where this is not explicitly required by regulatory obligations;
- the Small Business Commissioner of South Australia supported the key projects and projects outlined in our Draft Proposal which includes these Worst Served Customers Reliability Improvement programs, noting the importance of reliable service outcomes for small businesses and their customers;[47] and
- the Energy and Water Ombudsman of South Australia supported our proposed service levels and expenditure to support a reliability, resilience and safe distribution network, which include this Worst Served Customers Reliability Improvement programs, as being in the best interests of the South Australian community.[48]

7.1 Alignment to customer values research

To guide the development of expenditure forecasts that enable price-service outcomes that align with the expectations and preferences of our broader customer base, we engaged expert economic consultants to undertake a customer values research study (study). The study employed a partial profile discrete choice experiment to identify how much South Australian households and businesses are willing to pay through their electricity bills to achieve certain service outcomes.

One area of focus for the study was to identify how much customers may be willing to contribute on their annual electricity bills to decrease the number of customers that experience service interruptions in worst-served areas. The willingness to pay for this service outcome was of particular importance, as these programs target improvements for discrete sections of our network and will only affect certain customer segments. We therefore wanted to test the broader views of the general customer base who would be at large contributing for these service outcomes.

The survey results indicated, with a 95% level of confidence, that on average residential customers are willing to contribute an additional $9.39 ($2025) per year and commercial customers $23.48 ($2025) per year, on their annual electricity bills to improve service levels for 34,000 customers in worst served areas. Further, the results also indicated to improve service levels for 65,000 customers in worst served areas average residential customers would willing to contribute an additional $15.76 ($2025) per year and commercial customers $15.55 ($2025) per year on their annual electricity bills.

44 DemocracyCo, *Submission: SA Power Networks Draft Regulatory Proposal 2025-30*, 30 August 2023.

45 SACOSS, *South Australian Council of Social Service Submission on SA Power Networks' 2025-30 Draft Regulatory Proposal*, September 2023.

46 DEM, *South Australian Department of Energy and Mining* – Submission, October 2023.

47 SMCSA, Small Business Commissioner of South Australia – Consultation on SA Power Networks 2025-30 Draft Regulatory Proposal, 1 September 2023.

48 EWOSA, Energy and Water Ombudsman of South Australia – Submission to SA Power Networks: Draft Regulatory Proposal 2025-30, 29 August 2023.

Our recommended options for the Regional Reliability, LRF Improvement and Supply Restoration Improvement programs will collectively improve reliability for 47,664 customers. The forecast annual bill impact from these programs will be $1.82 ($2025) for residential customers and $12.79 ($2025) for small business customers, which is well below the amounts indicated in the customer values research.

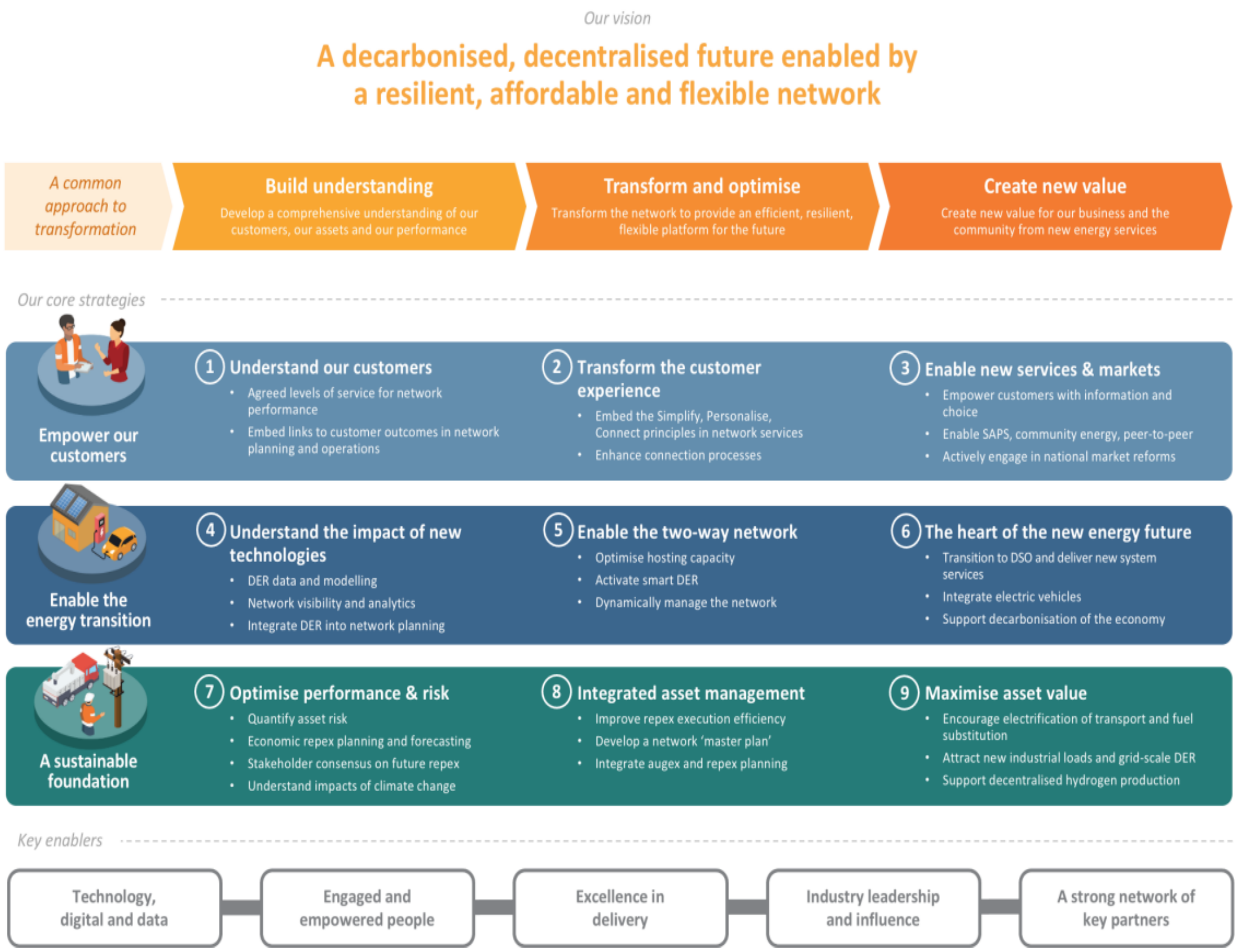
Therefore, this study indicates that in addition to these programs being supported by our customers through our engagement, and being economically efficient returning positive net benefits, they are also supported by the broader customer base. That is, the broader customer base is willing to pay and effectively subsidise network improvements to improve the relatability experienced by worst served customers.

7.2 Alignment with our vision and strategy

This business case which proposes expenditure to allow us to achieve an overall service outcome of maintaining underlying reliability performance for our customers, is aligned to progress to our overall company 'Network Strategy' and our vision within this strategy, displayed in Figure 9 below. This is noting that the program recommended in this business is aligned to several of the core strategies within the Network Strategy, as follows:

- 'empower our customers' – the program arises from a comprehensive, multi-staged consumer engagement program that saw us iterating our expenditure forecasts with our customers over five iterations to identify and align our expenditure to achieve the service level and price outcomes that our customers expect and prefer being mindful of alternatives and tradeoffs;
- 'a sustainable foundation' – the program provides outcomes for customers that:
  - are more equitable for customers across our network;
  - are efficient for customers – producing monetised value for customers, quantified by assessing the impact of network risks on customer service outcomes under a option versus do-nothing counterfactual;
  - providing upgrades that not only improve reliability but could provide additional network resilience to potential emerging effects of climate change; and
  - the programs have also been considered as part of a holistic approach of considering the role of our network repex versus augex solutions to achieve target service level outcomes.

Figure 9: SA Power Networks Strategic Vision and Core strategies



8 Reasonableness of cost and benefit estimates

We believe that our assumptions are reasonable, and our cost-benefit analysis methodology used to prepare the three reliability improvement program forecasts aligns with the recent AER statements on its expectation for formal quantitative risk assessments and cost-benefit analysis.

The key feature of our approach demonstrates the appropriateness of our assumptions and analysis are as follows:

- we have undertaken a thorough technical review of each candidate feeder for each program and its outage history to develop feasible improvement solutions tailored to each feeder and to estimate the expected improvement in reliability achieved by each solution;
- we have developed a schedule of solution-type unit costs to estimate the cost of each individual feasible solution developed through the above review. These solution types reflect upgrade approaches we are applying during the current RCP, and therefore, unit costs are calculated from actual costs and work volumes;
- to estimate reliability improvement benefits, we have calculated feeder-specific VCRs for each feeder, using the most recent AER published customer-type VCRs and our data on the customer volumes by customer type supplied by each feeder; and
- we have undertaken cost-benefit analysis of individual solutions to develop the optimal program, so that the program only contains the set of solutions that each individually provide a positive net benefit.