Business case: Augmentation - Capacity

2025-30 Regulatory Proposal

Supporting document [5.4.2]

January 2024

SA Power Networks

Empowering South Australia

Contents

Glossary

Acronym / term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Augex	Augmentation expenditure
Capex	Capital expenditure
CER	Customer Energy Resources
CESS	Capital Expenditure Sharing Scheme
CPMP	Connection Point Management Plan
DLF	Distribution loss factor
DNSP	Distribution Network Service Provider
EDC	Electricity Distribution Code
ESCoSA	Essential Services Commission of South Australia
ETC	Electricity Transmission Code
EV	Electric Vehicle
EVM	Enhanced Voltage Management
GDP	Gross Domestic Product
HILP	High Impact Low Probability
HV	High Voltage
ICT	Information and Communication Technology
LV	Low voltage
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
Opex	Operating expenditure
Planning Criteria	Distribution Network Planning Criteria
PV	Photovoltaic
QoS	Quality of Supply
Repex	Replacement expenditure
RCP	Regulatory Control Period
SACOSS	South Australian Council of Social Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCS	Standard Control Services
SPS	Service Performance Scheme
SWER	Single Wire Earth Return
TCA	Transmission Connection Agreement
TNSP	Transmission Network Service Provider
TSND	Temperature sensitive native demand
USE	Unserved energy
VCR	Value of customer reliability

1 About this document

1.1 Purpose

This business case supports forecast expenditure for the 2025-30 Regulatory Control Period (**RCP**) for SA Power Networks' capital expenditure (**capex**) on its capacity augmentation program, which comprises one input to our overall network augmentation expenditure (**augex**). This capacity component includes works required to meet or manage forecast demand[1] that necessitates the extension or upgrade of our sub-transmission, distribution and low voltage (**LV**) networks, including connection points and substations.

1.2 Expenditure category

- Network capex: capacity augex

1.3 Related documents

Table 1: Related documents

Ref	Title	Author
5.4.1	Augex Forecasting Approach	SA Power Networks
5.3.2	Repex Forecasting Approach	SA Power Networks
5.4.3	Connection Point Power Factors Letter	ElectraNet
5.7.3	CER Compliance Business Case	SA Power Networks
5.7.4	CER Integration Business Case	SA Power Networks
5.7.5	Demand Flexibility Business Case	SA Power Networks
5.7.6	Network Visibility Business Case	SA Power Networks
5.7.9	CER integration modelling methodology	SA Power Networks
5.9.3	Maintain underlying reliability performance program	SA Power Networks
5.9.5	Worst Served Customers Reliability Improvement Programs	SA Power Networks

[1] Demand refers to the supply of electrical loads. Constraints related to the output of embedded generation (i.e. reverse flow) are addressed via the CER Integration business case.

2 Executive summary

This business case recommends $208.6 million[2] in capacity driven augex for the 2025-30 RCP to expand or upgrade network assets to address the capex objectives in the National Electricity Rules (**NER**), namely complying with our regulatory obligations and requirements associated with the provision of Standard Control Services (**SCS**), meeting or managing the expected demand for SCS, and maintaining the quality, reliability and security of supply of SCS.[3]

A material increase in demand from macro factors such as electrification, particularly in the business, transport and the residential sector, up-take of Electric Vehicles (**EVs**) and renewable targets, as well as localised factors, such as in-fill housing and residential developments and commercial and industrial loads is the underlying driver for an increase in capacity augex compared to the 2020-25 RCP.

In considering how to respond to the identified need, we engaged with our customers who agreed, as reflected in the recommendations of the People's Panel, and as required by the capex objectives, that a capacity expenditure forecast is needed which maintains current levels of network services and security of supply whilst being mindful of energy affordability.

We applied a long-standing deterministic approach to capacity planning since before privatisation, including all previous Regulatory Proposals, providing a prudent and consistent level of supply security – this is pursuant to our Distribution Network Planning Criteria (the **Planning Criteria**). In response to our customer engagement outcomes and as an example of a top-down challenge to our forecast, our recommendation seeks to provide an alternative planning standard that reflects a desire to:

- recognise the general affordability concerns expressed by our customers;
- accept a moderate change in risk profile, whilst we further evaluate the potential for non-network solutions and flexible load connections to manage this demand; and
- reduce the rate of workforce scale-up required to deliver our overall capital program.

Our capacity augex investment plan for 2025-30 RCP was developed mindful of customers' long-term interests, aiming to deliver long-term levels of supply security and reliability, while balancing cost. To achieve this desired outcome, probabilistic (economic) analysis was applied as an additional filter on our Planning Criteria. This approach identified investments which produce quantitative benefits for customers that outweigh the costs of augex, except for work required for compliance and to meet our obligations under the ElectraNet Transmission Connection Agreement (**TCA**).

As discussed later in this business case, our position is that the current regulatory framework inadequately values High Impact Low Probability (**HILP**) events. Consequently, moving away from our Planning Criteria and adopting a probabilistic approach for capacity augmentation in 2025-30 will result in an increase in the risk that customers will experience a supply interruption. Our expenditure is also predominantly categorised as reinforcement (83%) rather than greenfield, further supporting our desire to maintain existing service levels to our customers.

In developing this recommendation, we considered alternative options including:

- a **base case** (Option 0 – $139.9 million) which consists of projects to meet compliance obligations and projects to relieve constraints forecast to occur at a 50% Probability of Exceedance (**POE**) level under normal operating conditions, as well as supporting capitalised expenditure relating to labour, procurement, and land acquisition;
- a **hybrid case** (Option 1 – $208.6 million) which includes all options in the base case combined with additional projects to relieve constraints forecast to occur at a 10 POE level under normal operating conditions, as well as projects to relieve forecast constraints at 50 POE level under contingency (N-1) conditions that have a positive benefit versus cost result in Net present value (**NPV**) terms; and

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2 Represents the capex in $m June 2022, excluding corporate overheads.

3 This is pursuant to section 6.5.7 of the NER.

- a **deterministic case** (Option 2 – $275.9 million) in which expenditure is consistent with the level of investment needed to maintain current levels of service, modelled using the methodology and approach outlined in our Planning Criteria.

The **recommended option** based on the options evaluated in this business case is **Option 1**, as it has the highest benefits versus costs (i.e the highest NPV), best balances customer affordability and risk and thereby best gives effect to the overall recommendations of our customers, our regulatory obligations and compliance requirements. Expenditure for option 1 is compared to historic and forecast capacity augex from 2010 to 2025 in Figure 1.

While Option 2 provides benefits to customers that outweigh costs and delivers greater long-term reliability and security of supply outcomes than Option 1, it does not adequately respond to the energy affordability concerns that our customers have told us to be mindful of.

Option 0 is negative in NPV terms and has a lower net benefit than options 1 and 2 and would result in widespread network security of supply risks, as lack of capacity leads to unmet customer demand which would need to be managed by shedding load. These outcomes would be unacceptable for our customers.

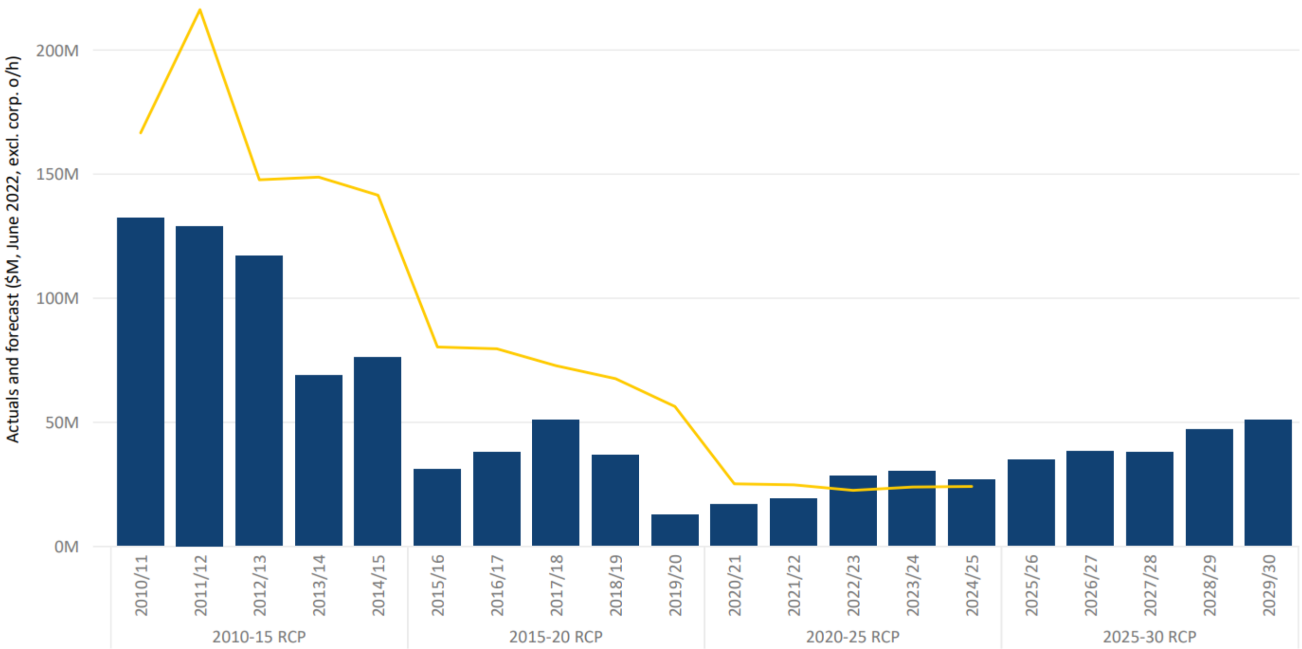

Figure 1: Historical and forecast capacity augex 2010 – 2025 and forecast expenditure for Option 1

3 Background

This business case justifies the total forecast network capacity related augex for 2025-30. This expenditure comprises several programs that each have their own specific contexts driving the need for network augex. When determining the overall capacity forecast, we ensured that the proposed projects do not overlap with other expenditure programs such as asset replacement (**repex**) and augex programs on reliability.

Capacity driven augex relates to works required to meet or manage forecast demand necessitating the extension or upgrade of our sub-transmission, distribution and LV networks including transmission connection points and substations.

3.1 The scope of this business case

Capacity augex can be defined into different categories and sub-categories as shown in Table 2.

Table 2: Description of capacity augex categories and sub-categories

Category	Sub-Category ID	Description
Connection Point	AUG001	Capacity augmentation resulting from ElectraNet works or requirements
Sub-transmission	AUG006	Subtransmission capacity augmentation
Substation	AUG004	Labour capitalisation for long term planning, network architecture and regulatory compliance
	AUG005	Substation capacity augmentation
	AUG008	Work required to maintain QoS within NER requirements
	AUG009	Substation capacity augmentation (land acquisition)
Distribution (11kV and 7.6kV)	AUG003	Feeder capacity augmentation
	AUG007	SWER capacity augmentation
Low Voltage	AUG002	LV augmentation expenditure (unrelated to reverse power flows) – reactive & proactive
	AUG010	LV Two Way Network (Quality of Supply, QoS)

Costs in this business case are provided in $June 2022, minus corporate overheads.

3.2 Regulatory context

Sub-transmission and distribution network augmentation is generated either from:

- requirements to upgrade our infrastructure resulting from changes to the Electricity Transmission Code (**ETC**), which we are obliged to give effect to as part of our regulatory obligations, or
- as an output of our planning process to ensure we can achieve the capex objectives in clauses 6.5.7(a)(1) and (2) of the NER. The criteria in sub-clause 6.5.7(c) further outline requirements for the way in which expenditure must be set to achieve the capex objectives.

Our forecasting and planning methodologies and procedures are designed around establishing and maintaining compliance with the capex objectives, as well as meeting obligations within the broader regulatory landscape including requirements relating to reliability and system security contained in Schedule 5.1 the NER, National and International Standards, Codes of Practice, the *Electricity Act 1996* (SA) and the South Australian Electricity Distribution Code (**EDC**).

3.3 Our performance to date

3.3.1 2020-25 RCP

In 2020-25 we forecast spending capacity augex of approximately $119.7 million across the categories shown in Table 3.

Table 3: Capacity Augmentation Expenditure 2020-25 RCP (Iteration 5.2)

	2020-25 RCP Allowance[4]	2020-25 Actuals[5] + Forecast
Connection Point (AUG001)	11.8M	1.4M
Sub-transmission (AUG006)	12.0M	17.7M
Substation (AUG004, AUG005, AUG008 & AUG009)	40.9M	51.1M
Distribution (AUG003 & AUG007)	7.7M	9.9M
Low Voltage (AUG002 & AUG010)	47.0M	38.5M
Fin Adj		**1.2**
TOTAL	**119.4M**	**119.7M**

The AER forecast of capacity augex included in its capex allowance for 2020-25 was $119.4 million. This was the lowest forecast of capacity augex in over 15 years, due to flat or declining demand forecasts for this period, lowering the need for capacity driven augex relative to earlier RCPs.

We expect our expenditure will be slightly above the AER allowance. Previously unidentified augmentation works have been required, such as the Morphettville substation upgrade, the Angle Vale to Virginia 66kV sub-transmission line and the Southern Outer Metro 66kV sub-transmission loop reinforcement projects. These projects were driven by demand changes over the period. Expenditure for these new projects was offset by deferred or cancelled projects[6]. We expect the Mount Gambier and Mannum Connection Point projects, deferred by ElectraNet, will be required in the 2025-30 RCP at a cost of $8.75 million. All deferred projects have been excluded from our Capital Expenditure Sharing Scheme (**CESS**) calculations so that customers are not impacted as detailed in our CESS attachment.

Expenditure for the past three RCPs have been outlined in Table 4.

Table 4: Actual Expenditure Comparison

	2010-15 RCP	2015-20 RCP	2020-25 RCP
Actual Expenditure[7]	$522.2M	$168.3M	$119.7M

4 $June 2022 excluding Network and Corporate overheads.

5 Actuals up to and including Nov 2023 in $June 2022 excluding Network and Corporate overheads.

6 These projects are: (1) another transmission connection point upgrade at a cost of $5m, also driven by an altered decision by ElectraNet and (2) a network augex project to upgrade a 66KV sub-transmission line between the regions of Myponga and Square Waterhole, driven by changes in our demand forecast and a decision by our business to prioritise capacity upgrades in other 66KV lines (Angle Value to Virginia, and Southern Outer Metro 66kV sub-transmission loop) that were deemed to present a higher risk to customer service – On the basis of customer consultation, we have no plans to proceed with this project in the 2025-30 RCP.

7 All expenditure in $June 2022 excluding Network and Corporate overheads.

3.4 Forecasting Methodology

We combine two methods to forecast network capacity related augex for the 2025-30 RCP: ‘Historic’ and ‘Modelled’. The key elements of each method are explained below. A detailed overview of the forecasting approach is outlined in reference document *5.4.1 - Augex forecasting approach - Methodology*.

3.4.1 Historic Method

The Historic method is used when historical expenditure has been steady and is not expected to change materially in the future - this capex has a recurrent nature, whereby the forecast remains consistent with historical levels and individual projects (investment needs) are identified and rectified in a short timeframe.

The categories in this business case for which the Historic forecasting method is applied are:

- AUG002 - LV and Distribution Transformers;
- AUG004 - Labour capitalisation for long term planning and network architecture; and
- AUG010 - LV Two Way Network (Quality of Supply (**QoS**)).

3.4.2 Modelled Method

The Modelled method is used for augex projects that have drivers and needs which exhibit a degree of variability - this includes meeting and managing demand for SCS and maintaining the security of supply of Distribution Services and the distribution system. The Modelled method is used to forecast capacity augex in the following categories:

- AUG001 - Capacity augmentation resulting from ElectraNet Works and power factor compliance
- AUG003 - Feeder capacity augmentation
- AUG005 - Substation capacity augmentation
- AUG006 - Subtransmission capacity augmentation
- AUG007 – Single Wire Earth Return (**SWER**) capacity augmentation
- AUG009 - Substation capacity augmentation

The Modelled Forecasting method incorporates a deterministic methodology that considers the forecast of future network demand, network capacity to deliver forecast demand, the subsequent identification of network or connection point thermal and voltage constraints and evaluation of options to alleviate the constraints. The method is underpinned by several of our detailed procedures, chiefly Planning Criteria and demand forecasting.

3.4.2.1 Demand Forecasting

Our demand forecasting predicts the long-term demand trends (including negative growth) of each network asset i.e., connection points, zone substations, sub-transmission (66kV and 33kV) and distribution feeders (11kV and 7.6kV) over a 5 to 20-year period.

We use a custom-built tool co-designed with the Australian Energy Market Operator (**AEMO**) to generate Connection Point and Zone Substation forecasts at 10 POE and 50 POE levels. The tool relies on the provision of data relating to measured / estimated substation demands, large block loads, embedded generation output, levels of installed PV generation / output in conjunction with system wide forecasts of demand and PV installations for reconciliation purposes.

Baseline forecasts are produced considering the trend of historic maximum demands with the effects of weather (30 years) and system changes removed. The baseline forecasts are then reconciled to the next level of the system (i.e., connection points are reconciled to the total demand forecast, zone substations are reconciled to connection point non-coincident forecasts). The reconciliation process accounts for macro-economic factors such as population growth, energy efficiency impacts and changes in electricity prices.

A statistical regression analysis of underlying temperature sensitive demand against historic temperature data is made to produce 10 POE and 50 POE forecasts for real power (MW). The historic temperature sensitive native demand (**TSND**) is determined by adding any embedded generation and calculated solar photovoltaic (**PV**) output data to the measured demand and subtracting any specified major customer / temperature insensitive loads.

$$TSND = Measured\ Demand + Embedded\ Generation + PV - Major\ Customer\ Demand$$

Adjustments are made to account for historic load transfers or spot load changes. Forecasts are then reconciled to upstream forecasts to produce reconciled forecasts, coincident and non-coincident to the upstream portion of the network. Coincident forecasts indicate the expected substation output when the upstream network peaks while the non-coincident forecast provides the expected maximum demand forecasts when the substation is expected to peak.

Sub-transmission demand forecasts utilise the Connection Point and Zone substation forecasts combined with peak recorded values to generate 10 POE and assumed 50 POE forecasts.

Distribution feeder demand forecasts utilise Zone Substation forecasts in combination with feeder peak recorded values to generate 10 POE and 50 POE forecasts.

3.4.2.2 Planning Criteria

The Planning Criteria sets out the methodology for identifying future capacity constraints across each of the relevant network asset categories and identifying the most efficient investment solution to relieve the constraint, with key steps as follows:

1. determine capacity ratings of network assets under system normal and emergency[8] conditions;
2. prepare long-term (5-20 year) demand forecasts at each network asset (as per methodology in 3.4.2.1);
3. compare forecast demand to rated capacity and identify the year when the forecast demand (at the relevant PoE level) exceeds capacity under system normal (N) or contingency (N-1) operating conditions;
4. prepare long-term development plans for regions describing sub-transmission line and zone substation projects and capacity upgrades (10-year horizon) and distribution feeders (5-year horizon);
5. prepare options / solutions to meet the need and timing requirements including cost and risk range for inclusion in the expenditure forecast; and
6. analyse credible options and select the most efficient project solution (highest NPV).

8 SA Power Networks Procedure 634 defines Emergency conditions as operating at or above 150% of nameplate capacity or defined hot-spot or top-oil temperature limits.

3.5 Distinguishing Capacity Augex from other expenditure streams

We recognise the need to clearly and transparently delineate capacity augex from other workstreams. The following definitions were made to distinguish and separate capacity augex from expenditure in other streams for which we have prepared separated business cases for our 2025-30 Regulatory Proposal.

3.5.1 Capacity Augex vs Customer energy resources (CER) Integration Expenditure

There are two broad categories of augex proposed for the Low Voltage network:

1. a **planned investment** program to increase Low Voltage network capacity to allow higher CER exports (i.e. alleviate CER curtailment), and
2. a **Business as Usual** (**BAU**) LV augmentation program to maintain QoS

<u>Planned investment program</u>

The planned investment program is detailed in our *5.7.4 CER Integration Business Case.* The CER Integration Program proposes expenditure to address export capacity constraints overvoltage issues that are forecast to occur on the network because of CER uptake. The program is based on detailed network modelling. The model, using a CER uptake forecast, identifies where thermal constraints and over voltages would occur on the network, and considers investment opportunities to address the network limitations so that higher levels of CER can be exported, thereby reducing the need to curtail CER via our flexible exports program.

The program proposes investments to increase hosting capacity where it is efficient. Individual distribution transformers and LV network mains are identified for proactive upgrade where the benefit of the upgrade outweighs cost. To ensure no double counting of expenditure with assets already planned for replacement in 2025-30, the investment program removes distribution transformers that are planned for replacement due to their condition.

<u>Business as usual (BAU) program</u>

The BAU program is required to address power quality non-compliance issues identified for 2025-30. The expenditure forecast for the BAU program is based on the historic expenditure to address issues with quality of supply as they become known, as detailed in section 5.2.

Our past investment in reactive responses to power quality non-compliance is captured in internal cost codes. Prior to 2023, all costs were captured within the AUG002 code. Since 2023, we separated all overvoltage quality of supply compliance expenditure and allocated it to a separate code (AUG010). Since 2017/18, we experienced an increase in overvoltage quality of supply expenditure (AUG010) with the cause being attributed to CER uptake having exceeded the latent hosting capacity of the network and CER systems being installed with non-compliant inverter settings.

Even as new CER systems are installed with compliant inverter settings and dynamic export control via our flexible exports program, the existing fleet of non-compliant and non-controllable CER has continued to cause quality of supply overvoltage issues. Estimates of inverter compliance indicate that up to 70% of the existing CER fleet installed across the network have non-compliant settings. Further uptake of dynamic export controlled CER systems in areas that already experience overvoltage issues will be exacerbated.

Historically the BAU Quality of Supply & LV Augmentation expenditure was split across three issues: overvoltage, undervoltage and, general maintenance, safety and capacity. The separating out of this expenditure has allowed for line of sight for the historical expenditure in the AUG010 category.

3.5.2 Defining Capacity vs Repex

The network asset replacement expenditure program within document *5.3.2 - Repex Forecasting Approach - Methodology* takes into account any planned replacements as part of the capacity augex program of work so that these are not double counted.

3.5.3 Defining Capacity vs Reliability Augex

All work to maintain or improve reliability is included in the Reliability Augex program in document *5.9.3 Maintaining underlying reliability performance and 5.9.5 integrated worst served customers reliability improvement programs* business cases and has been excluded from the capacity augex in this business case.

3.6 Industry practice review

We engaged an external consultant to review the network capacity planning approaches being implemented by other Distribution Network Service Providers (**DNSPs**) in the NEM and to consider potential alternative capacity planning standards, most notably, probabilistic approaches to achieving the codified output standard. Some key findings were that:

- many DNSPs use probabilistic analysis, however there is no consistency across the NEM with respect to how they undertake capacity planning and cost benefit analysis;
- a probabilistic standard can fail to account for the absolute potential impact of an outage. Network investments to mitigate HILP events could be desirable for customers but may be unlikely to proceed because the quantification of risks and benefits shows them to be uneconomic; and
- to achieve the optimal balance between a strictly economic approach, and the additional risks that may result from this approach, some jurisdictions have introduced a ‘safety net’. This approach allows them to mitigate the risks associated with events which have a low probability of occurring but are realistic and would have a substantial impact on customers.

The planning approach and expenditure outcome for Options 1 and 2, presented in this business case, are consistent with industry practice within the NEM.

4 The identified need

4.1 Regulatory context

The underlying driver for this investment is that demand is forecast to a level that will exceed the intended operating conditions of our assets, triggering consideration of the need to upgrade or extend our network, to accommodate increased customer demand. Failure to address this need will result in a reduction in the level of service experienced by our customers resulting from:

- a reduction in quality of supply compliance;
- increasing periods and quantity of customers being load shed (i.e., increase in unserved energy);
- decreasing network capacity to maintain security of supply during contingencies or planned maintenance; and
- compromising between asset condition and supply security (i.e., avoiding load shedding by operating our assets outside of their design ratings).

In considering potential responses to this driver, we considered the regulatory framework under NER and the National Electricity Law (**NEL**) and, in particular, how the capex is required to achieve the capex objectives and reasonably reflects the capex criteria, having regard to relevant capex factors. We also considered our relevant regulatory obligations and requirements under the NER, NEL, and our jurisdictional instruments. We then engaged with our customers on their desired service level outcomes balanced against price outcomes. As a result of these considerations, the identified need for the total sum of our capacity augmentation is as follows:

- to prudently and efficiently meet or manage expected demand for Standard Control Services[9] by responding to customers' concerns[10], identified through our consumer and stakeholder engagement process, regarding their service level recommendations that we:
  - maintain current emergency backup capability in the network, for response to HILP events;
  - use the same approach that has been in place since before privatisation to identify investment requirements with increasing demand;
  - maintain long term security of supply to current standards; and
  - remain mindful of energy affordability.
- to prudently and efficiently comply with all applicable regulatory obligations / requirements[11] relating to power quality, short circuit capability, system stability clearing times, reliability and system security;
- as part of our applicable regulatory obligations / requirements, to prudently and efficiently comply with Australian Standards and good industry practice[12], to ensure the distribution network is designed, constructed, operated and maintained such that a customer's point of supply complies with stipulated requirements; and
- also, as part of our applicable regulatory obligations / requirements, to prudently and efficiently comply with requirements outlined in our Transmission Connection Agreement with ElectraNet[13], which seeks to pass on obligations to comply with levels of reliability and security of supply as specified in the ETC.

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9 This is pursuant to clause 6.5.7(a)(1) of the NER.

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

11 This is pursuant to Clause 6.5.7(a)(2) of the NER, which requires expenditure in order to comply with all appliable regulatory obligations or requirements associated with the provision of standard control services.

12 This is pursuant to voltage requirements set out in AS60038, voltage fluctuations are contained within limits of AS/NZS 61000 and harmonic voltage distortions do not exceed values set out in AS/NZS 61000. These obligations are similarly specified in NER clause 5.2.1(a)(3), and in clause 5.2.3(b) and schedule 5.1 which specify quality of supply standards.

13 Upgrade works are mandated through the alteration of existing connection points categorised within the ETC or due to the timing of asset replacement works by ElectraNet, as approved by the AER as part of ElectraNet's most recent price Determination in 2023. Connection Point Substation augmentation expenditure is necessary to comply with our TCA.

4.2 Drivers for change

4.2.1 Increased state-wide demand

The latest demand forecast that we and AEMO undertook, projects a material and sustained increase in state-wide demand commencing in the last two years of the current RCP and continuing throughout 2025-30 and beyond. AEMO's South Australia 2022 and 2023 state demand[14] predicts the operational summer demand will increase at a Compounded Annual Growth Rate of 1.91% from 2022/23 to 2031/32. This is the most significant growth forecast for South Australia in the last decade[15].

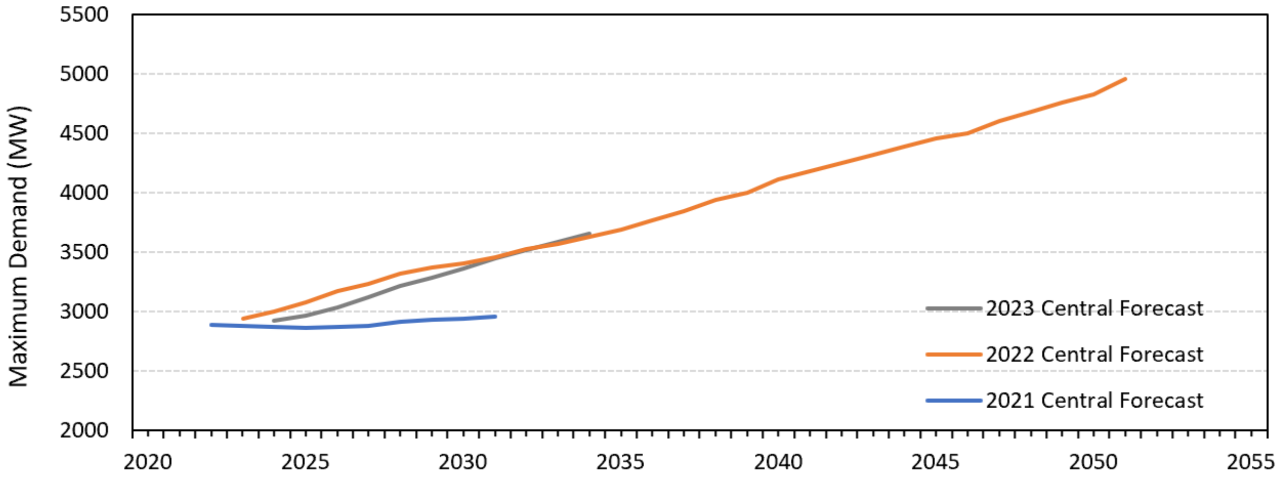

Figure 2: SA Operational Demand (summer 50% POE central (step change) scenario)

This increase is driven by macro factors such as Gross Domestic Product (**GDP**) growth, population growth, government net zero policies, increasing electrification in the transport, residential and commercial sectors, uptake of electric vehicles and home battery systems, as well as localised factors, such as in-fill housing, residential developments and new commercial and industrial loads.

These factors are key inputs into the demand forecast and have been included through reconciliation with AEMO's state-wide growth rate ('central' or 'Step Change' scenario), for South Australia as shown above in Figure 2. The combination of these factors is driving a step increase in capacity augex from the 2020-25 RCP.

4.2.2 Population and development growth

According to forecasting from Plan SA[16], State-wide population growth during the 2025-30 RCP is expected to be materially higher than the 1% per annum average during the past decade. Specifically Plan SA forecasts:

- 1.22% in 2021-31 under the medium growth scenario
- 1.55% over 2021-31 under a high growth scenario

Regions in South Australia are growing significantly faster than the state's average, particularly the outer suburbs of Adelaide. Adelaide's outer northern suburbs are growing exceptionally fast, with concentrated development in a number of residential growth areas including the master-planned developments of Virigina, Buckland Park and Angle Vale. Within the City of Playford government area, population growth is forecast to grow at an average of 2.4% between 2021-2031 as shown below in Figure 3, however growth areas are forecast to significantly exceed this average.

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14 See AEMO's Electricity Statement of Opportunities 2022.

15 AEMO's 2021 forecast for the period 2021/22 to 2030/31 had a Compounded Annual Growth Rate of just 0.2 percent.

16 https://plan.sa.gov.au/state_snapshot/population/population-projections

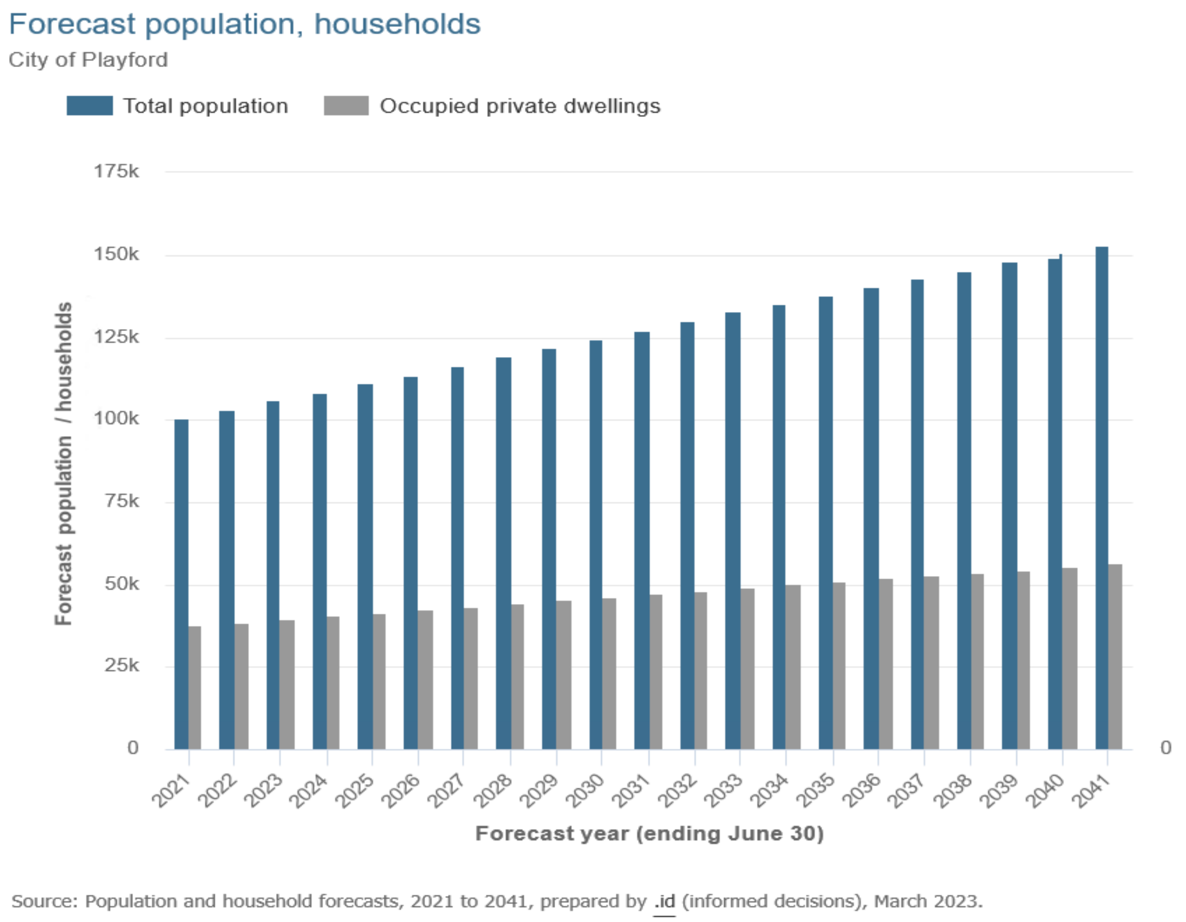

Figure 3: Population projects in City of Playford LGA[17]

Rapid growth is also expected in the outer southern suburbs and industrial west of Adelaide, most notably in master-planned development precincts such as Aldinga[18] and West End[19], as well as Dock One[20] in Port Adelaide. Sustained residential, commercial and retail load growth is expected throughout 2025-30 as key developments in these precincts are completed and progressively occupied.

Other areas are experiencing substantially higher population growth rates than the Plan SA projections, such as the Mount Barker region where growth is currently at 2.4% and expected to be maintained to 2035, with the majority of growth concentrated in the rezoned urban growth areas around Mount Barker[21].

A series of land releases under the South Australian Government's Better Housing Future Plan will be a significant driver of residential growth over 2025-30 and beyond. Rezoning has commenced in Hackham area with up to 2,000 new dwellings[22].

While population and development are not perfectly correlated with load growth, they provide highly reliable indicators of future network demand.

[17] https://forecast.id.com.au/playford

[18] https://renewalsa.sa.gov.au/projects/aldinga

[19] https://www.premier.sa.gov.au/media-releases/news-items/1000-new-homes-for-west-end-brewery-site

[20] https://kiteprojects.com.au/projects/dock-one

[21] www.mountbarker.sa.gov.au/__data/assets/pdf_file/0015/116421/Mount-Barker-2035-District-Strategic-Plan-Final.pdf

[22] https://plan.sa.gov.au/state_snapshot/better-housing-future/residential-land-release-and-rezoning

4.2.3 Solar PV systems

Currently, over 44% of PV-suitable dwellings in South Australia have a solar PV system installed. Growth in residential and commercial solar PV installations is expected to continue, increasingly coupled with battery systems, recognising that South Australian households have historically demonstrated high sensitivity to battery costs. While home and business solar PV systems have the tendency to reduce network demand, this is not necessarily the case during hot summer days when high temperatures persist into the late evening after the sun has set. The typical impact of solar PV systems on peak demand is reflected in Figure 4.

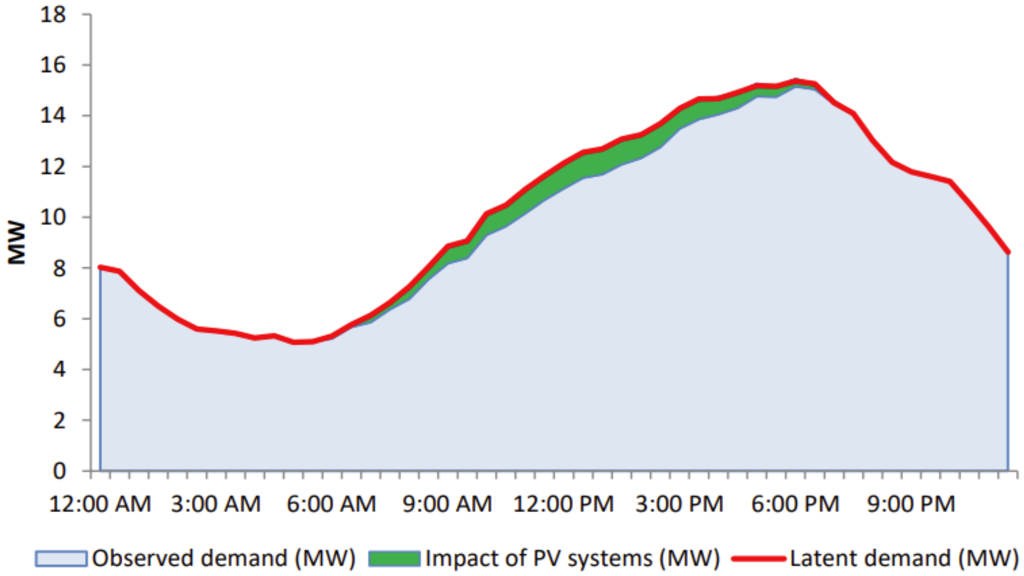

Figure 4: Example of measured demand compared with underlying (native/latent) demand

4.2.4 EV Uptake

To date, South Australia has lagged behind most Australian jurisdictions with EV uptake. The EV share (as a proportion of new car sales) in the first half of 2023 is at 6.5%[23], compared with 9% in NSW and 21.8% in ACT. However, this underlines the significant headroom for growth and a number of state-specific factors point to a strengthening in 2025-30, including:

- South Australian Government policy initiatives, including a $3,000 subsidy and three-year exemption from registration fees for new EV purchases, as well as the repeal of the EV tax which was due to commence in 2027.
- the South Australian Government's commitment to transition its 6,500 vehicle fleet to EVs by 2030; and
- the rollout of the Statewide EV charging network. The South Australian Government committed significant funding to this rollout. More than 50 charging stations have been installed so far, placing South Australia ahead of every jurisdiction on a per capita basis except Tasmania.

[23] See *State of EVs*, July 2023, Electric Vehicle Council.

4.2.5 Transmission Connection Point Substation Power Factor

The connection point expenditure category has seen a substantial increase with new TCA obligations driving a material increase in the 2025-30 RCP. Under the terms of the TCA, we have an obligation to comply with a power factor range at transmission connection point substations.

We are failing to meet these obligations due to increasing capacitive loads on our network, resulting in transmission over-voltage and ultimately compromising the state's system security (refer to *5.4.3 Connection Point Power Factors Letter*). A large component of the 'Connection Point Substation' augex includes a program of work to address the power factor technical obligations in the TCA. Failure to address this obligation will result in increasing levels of non-compliance over time as the trend is expected to be driven by the changing nature of customer energy use. The implications of the TCA requirements for the 2025-30 RCP are detailed in Section 5.1.

To better understand the fundamental drivers behind this change in capacitive reactive power, we are conducting research, aimed primarily at identifying key contributors to capacitive reactive power behaviour of residential loads via appliance testing and reconciliation to measured network trends. Findings from preliminary testing data indicate there is no single type of appliance that is driving this trend, but rather the aggregated contribution from modern appliances with capacitive rectifying circuits. This behaviour can be seen when appliances are in use, but also when they are on standby, which aligns with the observed capacitive flows on the network at low demand times.

5 Compliance-driven Expenditure

Compliance-related expenditure represents a substantial proportion of the total augex capacity forecast. It is comprised of the *Connection Point* (AUG001) and *Low Voltage* (AUG002 and AUG010) categories. The compliance-driven expenditure is required and included within all options considered in this business case and is therefore addressed separately within this section.

5.1 Connection Point (AUG001) Costs

A total of $50.8 million is required to meet the identified need of complying with regulatory requirements in relation to joint planning with ElectraNet. This expenditure is comprised of:

- $15.4 million on three joint-planning connection point upgrades to meet requirements within the ETC, due to the timing of asset replacement works by ElectraNet;[24] and
- $35.3 million on projects to meet our obligation in the TCA to comply with a power factor range at Transmission Connection Point Substations.

In relation to the $35.3 million allocated to TCA compliance projects, this was informed by formal notification from ElectraNet on 21 September 2022 advising that the capacitance of the distribution system is contributing to the occurrence of unacceptably high voltage levels on the South Australian transmission system, especially at times of low demand. This results in a compliance with the Technical Obligations included in Schedule 6, Part B item 3 of the TCA, as provided for in Schedule 5.3.1a(d) of the Rules.

Following this notification, we developed a plan in consultation with ElectraNet to identify and remedy the non-compliances (in the 2025-30 RCP). Subsequent correspondence (refer to *5.4.3 Connection Point Power Factors Letter*) further clarified ElectraNet's position around the need and timing, recommending action to restore compliance without delay.

TCA compliance projects seek to address over-voltage issues by installing 66kV and 11kV reactors at targeted locations supplied by 66kV Transmission Connection Points. Failure to address this obligation would increase levels of non-compliance over time as the trend is expected to be primarily driven by the changing nature of customer in-home appliances.

The regulatory investment test for distribution process for connection point upgrades is scheduled to commence in quarter 1 of 2024 with the publication of the options screening report.

5.2 Low Voltage Quality of Supply Compliance (AUG002 and AUG010) Costs

Expenditure of $35.78 million is required to meet the obligations associated with our Low Voltage QoS expenditure category (AUG002 and AUG010). This program consists of LV supply remediation works to maintain compliance, expenditure to address existing areas of non-compliant overvoltage attributed to current levels of CER up-take, and expenditure to maintain thermal limits of distribution transformers.

To meet the identified need of maintaining QoS compliance, our low voltage expenditure has been generated from the following triggers for investment:

1. overvoltage issues
2. undervoltage issues
3. thermal limitations; and
4. other reactive power quality compliance issues (harmonics, flicker, neutral voltages).

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[24] As approved by the AER as part ElectraNet's most recent Determination in 2023.

5.2.1 Forecasting Quality of Supply Expenditure

Historic and forecast expenditure across the AUG002 (undervoltage, thermal and other) and AUG010 (overvoltage) is shown in Figure 5.

In 2008 and 2009, South Australia experienced record breaking heatwaves resulting in reliability performance of LV networks not meeting community expectations, therefore targeted investment programs were proposed and delivered during the 2010-15 RCP to address thermal limitations. Throughout the 2015-20 RCP, a decline in demand growth rates and reduced severity of heatwaves led to a declining trend in expenditure for thermal limitations and overall LV network augmentation until 2017/18. It is notable that the uptake of CER, specifically rooftop solar PV during 2015-20, lead to an observable increase in overvoltage QoS expenditure from 2017/18 to address overvoltage issues in the BAU Quality of Supply program. It is possible that at this point (2017/18), the evolving capabilities of inverter systems provided more visibility of voltage levels seen by at a customer's supply and latent hosting capacity of low voltage networks began to be exceeded, resulting in overvoltage becoming more prevalent.

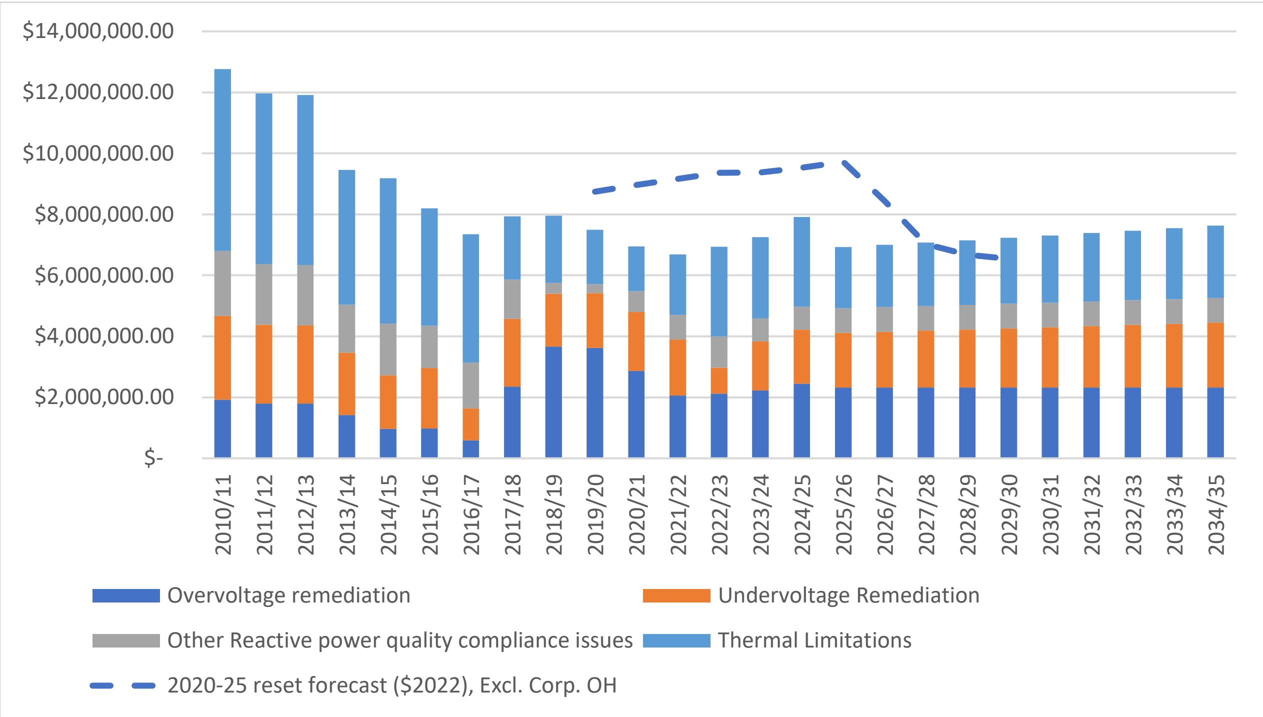

Figure 5: Historical and forecast augmentation expenditure for low voltage quality of supply (AUG002 and AUG010)

5.2.1.1 Overvoltage and Undervoltage

Prior to 2020-25, South Australian low voltage networks were challenged with almost no visibility or monitoring capabilities to identify QoS issues. Instead, we relied on customer enquiries to direct investigations and ultimately drive expenditure.

2020-25 expenditure

As part of our 2020-25 RCP Regulatory Proposal, we detailed how the effects of world leading percentiles of solar PV uptake was impacting LV networks in South Australia and how reliance on reactive approaches to power quality were no longer sustainable.

The plans put forward in our 2020-25 Regulatory Proposal focused on improving visibility, fitting more solar on to the network, managing immediate issues and risks, and building the foundations for the continued uptake of CER into the future. Since then, we have successfully delivered on these plans, developing flexible exports and implementing data analytics capabilities to improve visibility of our LV network using data from smart meters and other devices.

From 2016 to 2020, customer enquiry volumes reached new records each year consequentially driving expenditure upward. During 2020 and 2021, as part of our response to urgent system security risks in South Australia, we undertook a $10 million capital program to implement Enhanced Voltage Management (**EVM**) across 140 of our larger zone substations. The primary driver was to develop an emergency voltage raise capability to rapidly shed large amounts of small-scale solar if required to support AEMO during a minimum demand contingency event. The equipment upgrades made via this program have also enabled us to activate Line Drop Compensation at these substations, a technology that automatically raises or lowers the voltage setpoint at the substation depending on load. This has reduced daytime voltage rise due to solar PV without creating under-voltage conditions at times of peak demand.

As can be seen in Figure 6 below, this has proven very beneficial in mitigating customer over-voltage issues in the short term, with customer over-voltage enquiries falling as the EVM program rolled out through 2020 and 2021, returning to 2016 levels by 2022. This investment and subsequent reduction in enquiries led to an offset in expenditure during the first two financial years of the 2020-2025 RCP to address overvoltage non-compliance.

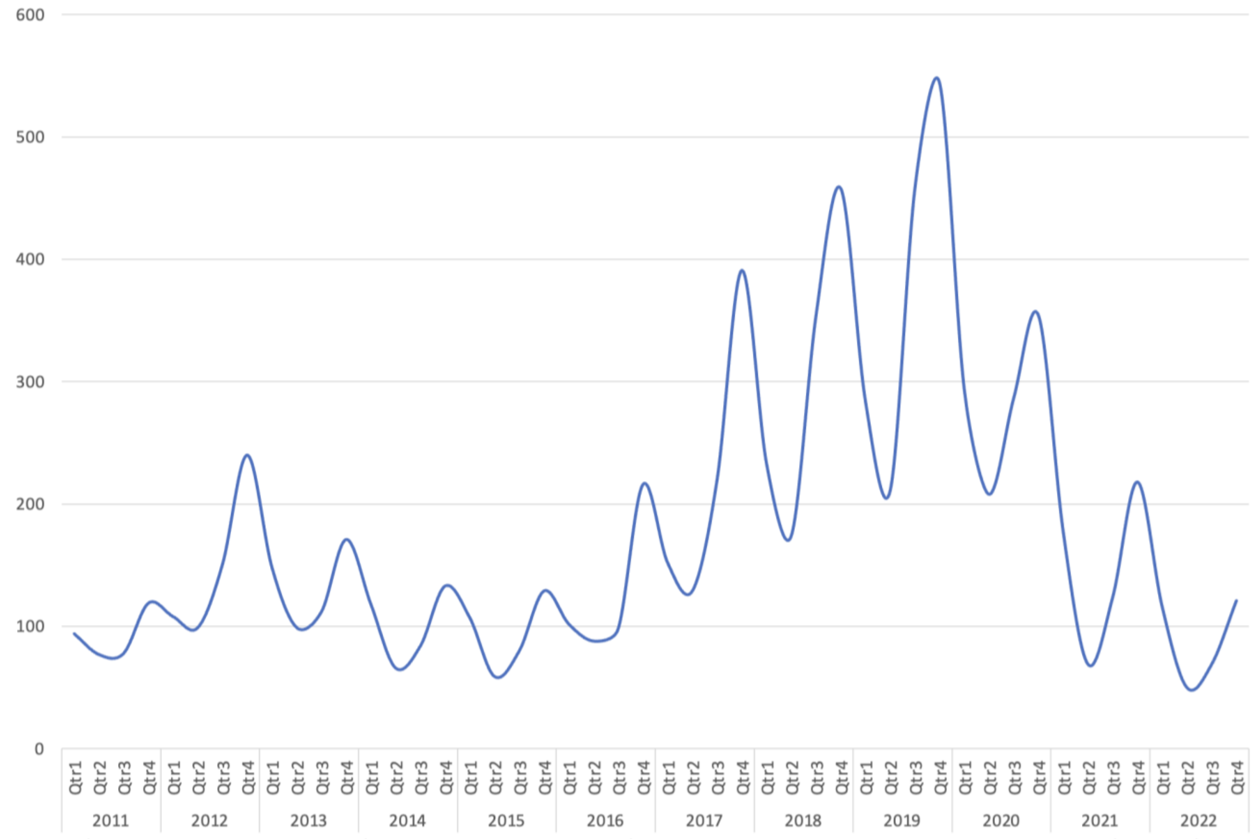

Figure 6: Historical volumes of customer enquiries relating to overvoltage issues per quarter in each year between 2011 to 2022.

In 2022/23, we established and operationalised the Network Visibility and Modelling program to accurately and efficiently identify thermal load constraints across LV Networks and prioritise investment to reduce transformer failures and fuse operations. Refer to the document *5.7.9 - CER Integration Modelling Methodology* for details on how these estimations are completed. Further, in 2023 data analytics packages of smart meter voltage data were operationalised to identify areas of the low voltage network that experience non-compliant voltages due to the existing levels of CER uptake.

2025-30 expenditure

With our proposed CER Integration Program for 2025-30 containing capacity investment in the LV network to resolve overvoltage associated with new CER installations, there is the potential of overlap between the AUG010 program and the CER Integration Program[25].

To account for this overlap, we initially forecast that the BAU overvoltage quality of supply expenditure (AUG010) would return to the pre-solar uptake level. However, our separately proposed Network Visibility program (refer *5.7.6 - Network Visibility - Business Case*) will provide enhanced abilities to monitor voltage performance across significantly more areas of our low voltage networks. We expect this program will drive a considerable increase in identification of sites experiencing voltage non-compliance due to existing levels of CER installations. As noted in Section 3.5.1, continued uptake of CER is expected to be controllable via our flexible exports program, however self-consumption of new systems will continue to erode underlying demand and result in some level of unavoidable overvoltage issues.

The combination of increased visibility, continued high uptake of CER and load growth forecast during 2025-30 is likely to result in increasing network voltage non-compliance, requiring greater levels of expenditure than were experienced in the pre-solar period (i.e. prior to 2016/17).

Any decrease in the BAU expenditure to avoid a potential overlap with the CER integration program is forecast to be exceeded by additional expenditure required to address overvoltage that are detected via the Network Visibility Program as a result of the issues described above.

Cognisant of our customers' concerns for cost of living pressures, we elected to retain the current level of expenditure, rather than an increase, as a means of gradually progressing toward achieving overall compliance. This will allow for prudent and efficient expenditure over 2025-30 and defer any uplift in resources for additional volumes of work. Our network visibility program will provide insights to the extent of compliance issues across the South Australian distribution network to inform any need to change approach during the 2030-35 RCP.

5.2.1.2 Thermal

Expenditure to address thermal limitations in LV networks is proposed to be kept consistent with our recurrent historic expenditure in 2020-25. Although significant demand increases are now forecast for South Australia, we are not proposing increases in expenditure, having considered the following:

- augmentation works undertaken for the purpose of voltage compliance and other reactive power quality compliance issues will overlap with some areas of thermal limitation;
- augmentation works undertaken in the CER Integration program will overlap with some areas of thermal limitations; and
- our proposed Demand Flexibility program will be supported, and subsequently unlock the ability to control a limited amount of load connections to avoid some constraints from being realised.

5.7.9 - CER Integration Modelling Methodology details the process used to identify LV constraints resulting from forecast load growth, as well as the linkages between capacity driven augex and the above programs to prevent overlaps in work programs.

5.2.1.3 Other reactive power quality compliance issues

Some customers experience power quality compliance issues with harmonics, voltage instability and spikes or electric shock associated to neutral voltages exceeding the standards. Due to the nature of these issues being caused by certain types of customer equipment which cannot be readily predicted or identified via smart meter voltage measurements, issues are identified reactively.

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[25] It is worth noting that the AUG010 program has historically included expenditure to address power quality issues that were unrelated to CER uptake.

After receiving information from customers about QoS concerns, we undertake field investigations, install temporary voltage monitoring devices and then determine the best way to fix the problem. Recurrent expenditure based on historic trends is included in this proposal.

Further details are provided in *5.4.1 Augmentation Expenditure (Augex) Forecasting Approach*.

6 Comparison of options

We considered a range of options for capacity augex for 2025-30, each setting out different outcomes for costs, benefits and risk. Within all options, the compliance expenditure outlined in Section 5 is included.

6.1 The options considered

Table 5: Summary of options considered

<table>
<tr><th>Option</th><th>Description</th></tr>
<tr><td>Option 0 (Base Case)

Essential Compliance plus ‘N’ projects justified at 50 POE level</td><td>The Base Case option comprises three elements:
1) minimum expenditure required to meet our compliance obligations;
2) projects required to avoid risks of unserved energy forecast to occur at a 50 POE level under normal operating (‘N’) conditions; and
3) supporting capitalised expenditure relating to labour, procurement, and land acquisition.

The compliance expenditure occurs in the Connection Point and Low Voltage expenditure categories. The Connection Point compliance obligations are directly from the joint-planning and connection point agreements with ElectraNet [26]. Low voltage refers to QoS obligations[27].

The Base Case projects and their associated expenditure are included in all options.</td></tr>
<tr><td>Option 1 (Hybrid Case)

Probabilistic Planning Approach plus ‘N’ projects justified at 10 POE level</td><td>This option combines probabilistic and deterministic approaches to produce targeted investment in two distinct categories:
1) projects required to avoid unserved energy risks forecast at a 10 POE level under normal operating conditions; and
2) projects required to address contingency (N-1) scenarios that are NPV-positive to deliver in 2025-30, identified via the application of probabilistic (economic) analysis.

This option presents a balanced approach to expenditure over the 2025-30 RCP that:
▪ recognises and assists with the general affordability concerns expressed by our customers;
▪ provides an opportunity for the maturation of non-network solutions and other developing technologies (e.g. flexible load connections) to address the demand forecast; and
▪ manages the rate of workforce scale-up required to deliver the capital program.</td></tr>
<tr><td>Option 2 (Deterministic Case)

Planning Criteria</td><td>This option represents our ‘maintain current levels of service’ approach as used for all previous Regulatory proposals.

It uses our Planning Criteria to ensure there is no reduction in customer’s supply security or back-up capability – an outcome our customers supported during the engagement for this proposal.

This option includes several projects that address contingency (N-1) scenarios but are NPV-negative, together with the NPV-positive projects included in Option 1.</td></tr>
</table>

26 ElectraNet and SA Power Networks jointly maintain a Connection Point Management Plan (**CPMP**) which outlines the predicted timing and high-level scope of new connection points, connection point upgrades and deferral solutions to connection point constraints via SA Power Networks’ distribution network.

27 Low voltage network augmentation is generated from recurrent expenditure within the QoS remediation program. This program consists of LV supply remediation works to maintain compliance, expenditure to address existing areas of non-compliant overvoltage attributed to the current levels of CER up-take, and expenditure to maintain thermal limits of distribution transformers.

6.1.1 Options investigated but deemed non-credible

A further option was investigated being the extension of Option 2 with additional projects that deliver market benefits within the Fleurieu Peninsula and outer metro regions. This option was explored with customers in our engagement program but has been disregarded given the affordability concerns expressed by our customers.

This option has been deemed non-credible and has not been evaluated further within this business case.

6.2 Option 0 (Base Case)

This section outlines the cost and benefits of expenditure required to meet our compliance obligations, coupled with expenditure on capacity augex projects that are required to relieve constraints arising at a 50 POE level under normal operating conditions, and supporting capitalised expenditure relating to labour, procurement, and land acquisition.

The complete list of projects in the Base Case and their associated cost, categorisation and the key driver of investment, is provided in Appendix C.

6.2.1 Costs

The capex breakdown over 2025-30 is outlined in the Table 6, a summary of all projects included and the inclusion criteria is provided in Table 19:

Table 6: Option 0 Total Capex by Category

Cost Type	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025 - 30
Sub-transmission Capex	6.26	2.04	0.05	8.21	4.46	**21.01**
Substation Capex	6.37	9.51	7.88	2.96	5.05	**31.77**
Distribution Feeder Capex	0.27	0.13	0.00	0.04	0.07	**0.52**
Connection Point Capex	7.53	9.72	2.10	11.92	19.52	**50.79**
Low Voltage Capex	7.16	7.16	7.16	7.16	7.16	**35.78**
TOTAL	27.58	28.55	17.18	30.29	36.26	**139.86**

The capacity augex investment for Option 0 is the minimum expenditure to meet our essential compliance obligations, totalling $139.9 million. Compared with the 2020-25 RCP allowance, this is an overall increase of $20.4 million. This is reflected in Figure 7 below.

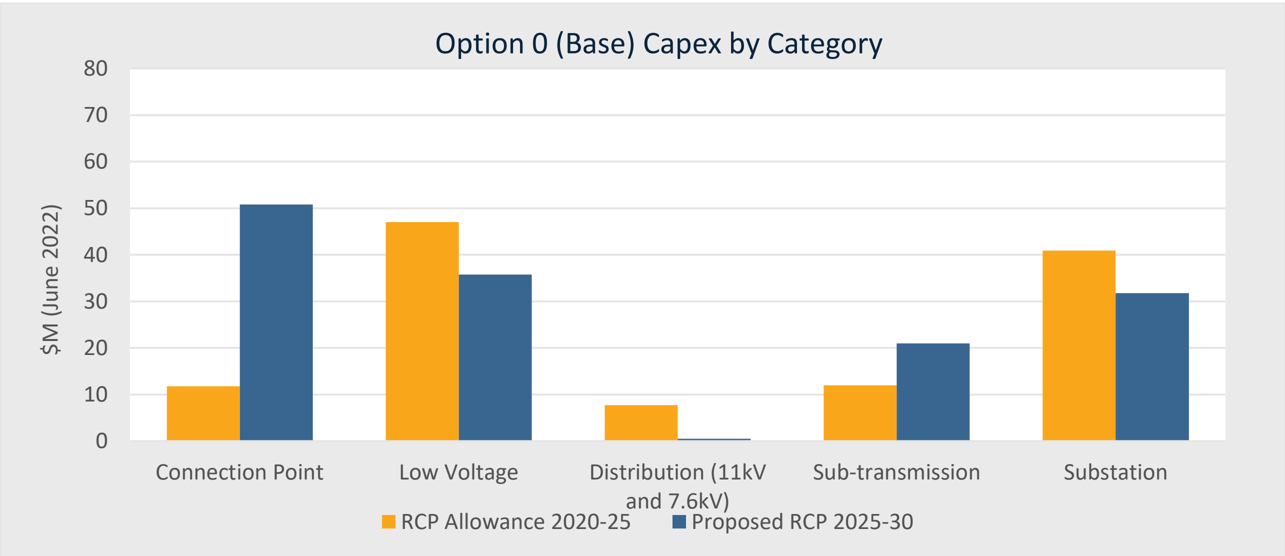

Figure 7: Category capex compared to RCP 2020-25 allowance.

6.2.2 Risks

Table 7 summarises the highest residual risk level in each risk consequence category from the risk assessment table in Appendix B.

Table 7: Option 0 (Base) risk assessment summary

Risk consequence category	Current risk level[28]
Performance and Growth – Financial impact	High
Network - Failure to transport electricity from source to load	High
Customers - Failure to deliver on customer expectations	High
Overall risk level	High

The risk assessment for the base case demonstrates that the projected unserved energy and financial implications inherent with this investment program is likely to be untenable for our customers. The impact to both residential and commercial / industrial sectors would be profound and erode trust. The risk attributable to the different segments of the distribution network is shown in Figure 8.

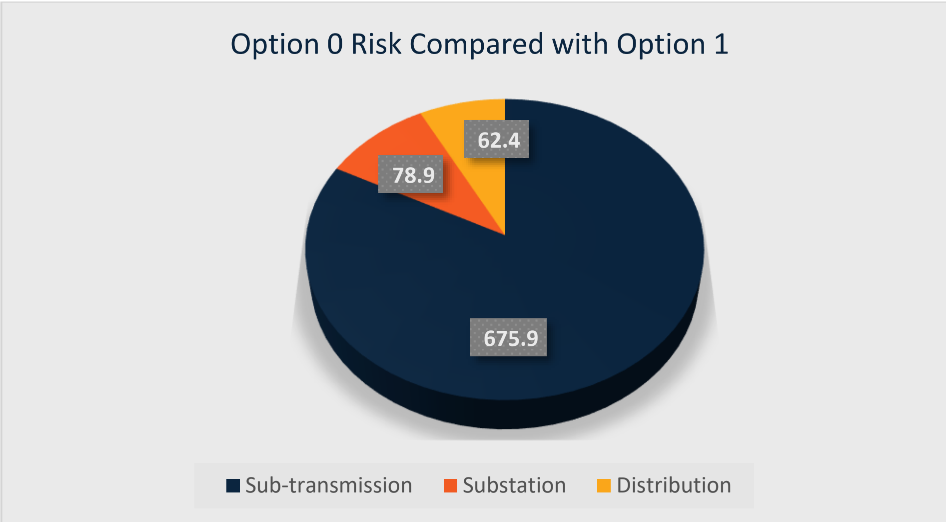

Figure 8: Option 0 risk ($M June 2022) by category.

6.2.3 Quantified benefits

The benefits by expenditure type over the 2025-30 RCP and 2030-35 RCP is outlined in Table 8.

Table 8: Option 0 Benefits by Expenditure Type ($m Jun 2022 Real)

Benefit Type	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025 - 30	2030-31	2031-32	2032-33	2033-34	2034-35[29]	Total 2025-35
Sub-transmission	0.00	0.26	0.67	1.02	1.62	**3.57**	2.22	2.97	3.94	5.18	6.74	**24.62**
Substation	0.00	0.00	0.18	0.37	0.57	**1.12**	0.84	1.21	1.85	2.85	4.13	**12.01**
Distribution Feeder	0.09	0.82	0.98	1.18	1.39	**4.45**	1.63	1.90	2.20	2.53	2.90	**15.60**
TOTAL	**0.09**	**1.08**	**1.84**	**2.56**	**3.58**	**9.15**	**4.69**	**6.07**	**7.99**	**10.57**	**13.77**	**52.23**

6.2.4 Unquantified benefits

The only benefit of the base case not already quantified is the ability to meet the minimum compliance obligations of the NER and EDC in relation to power factor compliance obligations at transmission connection points. Based on our engagement, this does not reflect customer expectations.

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28 The level of risk post current controls (ie after considering what we currently do to mitigate the risk).

29 The annual benefit beyond 2035 (to 2045) is the same as the 2034-35 value.

6.3 Option 1 (Hybrid Case):

This option builds on the Base Case with targeted investment in the *Sub-Transmission, Substation* and *Distribution Feeder* expenditure categories identified via a hybrid planning approach comprised of two elements:

1) ***probabilistic planning approach (N-1)*** – applies a cost-benefit assessment of contingency (N-1) projects identified by applying our Planning Criteria to determine if network investment is justified; and
2) ***deterministic planning approach (POE 10 for N)*** – investment in projects to resolve constraints under system normal (N) conditions.

The complete list of projects in Option 1 and their associated cost, categorisation and the key driver of investment, is provided in Appendix C.

6.3.1 Description

As a first step, the Planning Criteria are applied to generate project investments as per Option 2 (Deterministic Case): Planning Criteria. Probabilistic assessment is then applied to identify projects for which benefits (measured by applying the Value of customer reliability (**VCR**)) outweigh costs and thereby produce a positive NPV result.

For contingency (N-1) projects, only those projects with benefits outweighing costs and thereby producing a positive NPV are included. This option results in the deferral of projects resolving constraints under contingency (N-1) conditions that would otherwise have been required to comply with our Planning Criteria.

Projects to address constraints under system normal (N) conditions are included where the constraint is forecast to occur under 10 POE conditions, regardless of NPV.

There are two (2) high growth areas with forecast feeder level constraints under system normal (N) conditions where the constraint is forecast to occur under 10 POE conditions. Due to the expected high cost to resolve these constraints, it is prudent to subject these constraints to further scrutiny and consider deferring part or all of the investment to maximise benefits .

These constraints are primarily located in areas of high residential growth stemming from population relocation to areas otherwise undeveloped (greenfield development). Exhausting all available options to extend existing feeders or construct additional ones from current zone substations, our capacity plan advocates for the establishment of the Mount Barker East and Gawler East zone substations to cater to the significant growth, with a cost of $16.5 million and $14.4 million respectively.

The rapid development of Mount Barker, combined with limited infrastructure planning coordination, poses challenges should we delay all activities related to the establishment of the new substation, including radial 66kV sub-transmission, until 2030-35. To address this risk, we propose a staged approach, allocating 25% of the overall project investment for the 2025-30 RCP.

In collaboration with the Housing Infrastructure Planning and Development Unit within the South Australian Government Department of Trade and Investment, we are actively engaged in ensuring the long-term infrastructure planning needs in key growth areas within Greater Adelaide are addressed. As a result of these endeavours to strategically align policies and infrastructure needs, we recommend deferring the Gawler East substation project until 2030-35 to maximise benefits.

6.3.2 Costs

The capex breakdown over the 2025-30 RCP is outlined in Table 9, a summary of all projects included and the inclusion criteria is provided in Table 19.

Table 9: Option 1 Total Capex by Category ($m Jun 2022 Real, excluding network and corporate overheads)

Cost Type	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025 - 30
Sub-transmission Capex	7.39	6.97	13.50	16.98	4.46	**49.31**
Substation Capex	12.28	14.19	15.16	8.39	16.93	**66.94**
Distribution Feeder Capex	0.60	0.18	0.01	2.35	2.61	**5.75**
Connection Point Capex	7.53	9.72	2.10	11.92	19.52	**50.79**
Low Voltage Capex	7.16	7.16	7.16	7.16	7.16	**35.78**
TOTAL	**34.95**	**38.22**	**37.93**	**46.80**	**50.68**	**208.56**

Investment under Option 1 results in a recommended spend of $208.6 million in capacity augex. The comparison with the 2020-25 RCP allowance is shown below in Figure 9.

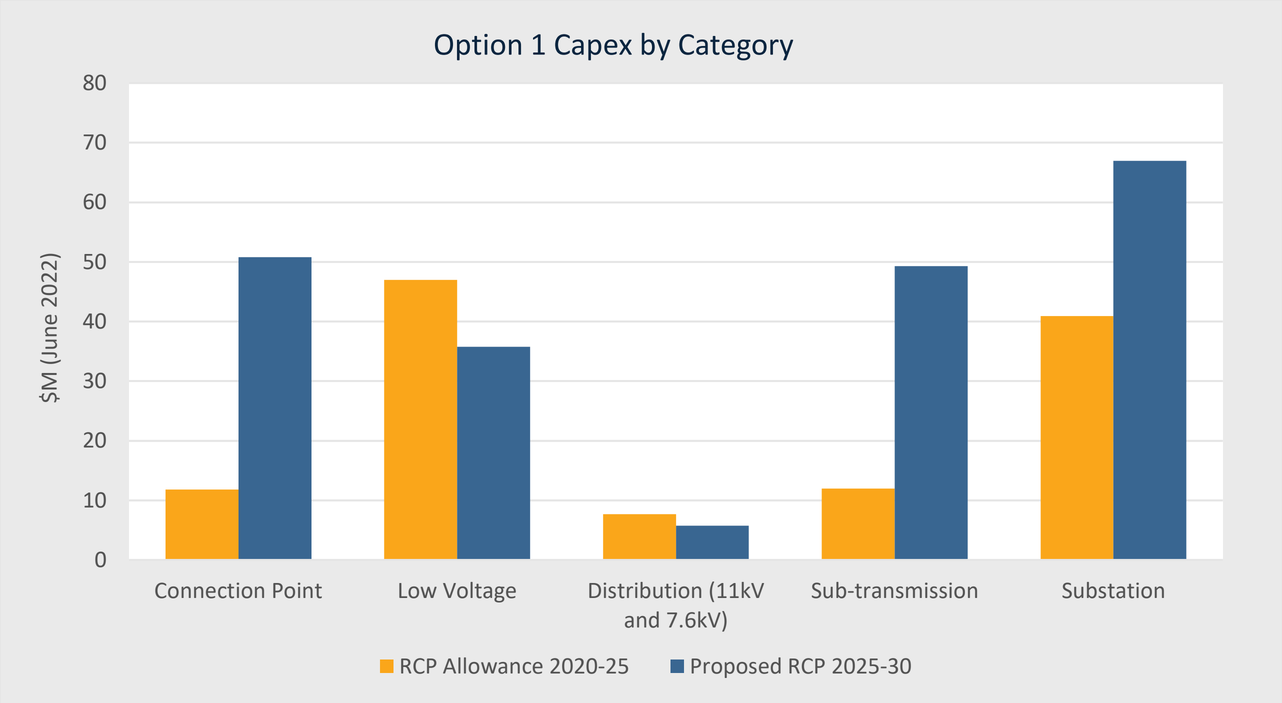

Figure 9: Category capex compared to RCP 2020-25 allowance.

6.3.3 Risks

Table 10 summarises the highest residual risk level in each Risk consequence category from the risk assessment table in Appendix B.

Table 10: Option 1 Risk assessment summary

Risk consequence category	Residual risk level[30]
Performance and Growth - Financial impact	Low
Network - Failure to transport electricity from source to load	Medium
Customers - Failure to deliver on customer expectations	Low
Overall risk level	**Medium**

[30] The future level of risk once treatments proposed in this option have been implemented.

In addition to the summary, the following specific risks are associated with Option 1:

- our ability to transfer load under planned and emergency conditions may not be able to be maintained;
- new planning approach could introduce a risk level SA Power Networks is not accustomed to;
- current emergency backup capability in the network for response to HILP events may not be able to be maintained. This may result in:
  - extended outage times for some customers; and
  - risk deterioration in reliability resulting in extended outage times for some customers; and
- long term security of supply to current standards may not be able to be maintained.

The risk attributable to the different segments of the distribution network is shown in Figure 10.

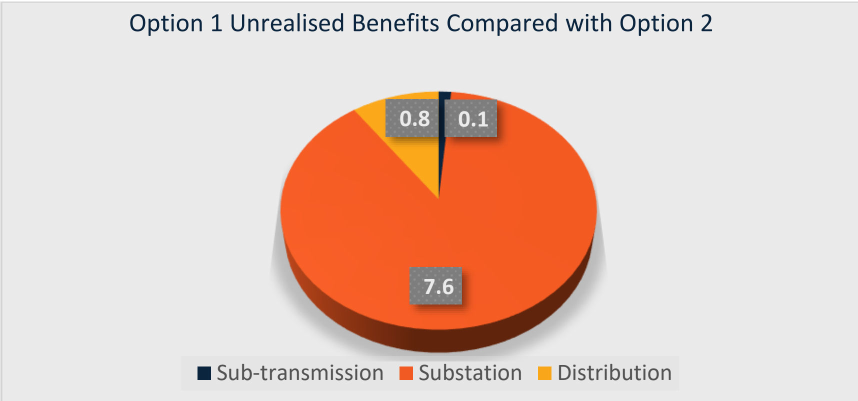

Figure 10: Option 1 unrealised benefits ($M June 2022) by category from Option 2.

6.3.4 Quantified benefits

The benefits by expenditure type over the 2025-30 RCP and 2030-35 RCP is outlined in Table 11.

Table 11: Option 1 Benefits by Expenditure Type ($m Jun 2022 Real excluding network and corporate overheads)

Benefit Type	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025 - 30	2030-31	2031-32	2032-33	2033-34	2034-35*	Total 2025-35
Sub-transmission	0.00	2.92	4.59	10.03	15.28	**32.83**	22.21	31.17	43.01	58.11	76.44	**263.77**
Substation	0.00	0.39	0.68	1.00	1.87	**3.94**	2.96	3.83	5.07	6.72	8.82	**31.36**
Distribution Feeder	0.35	1.10	$1.28	1.56	3.37	**7.66**	4.01	4.51	5.05	5.65	6.31	**33.18**
TOTAL	**0.35**	**4.41**	**6.55**	**12.58**	**20.53**	**44.43**	**29.18**	**39.51**	**53.13**	**70.48**	**91.57**	**328.31**

*Note that the annual benefit beyond 2035 up to 2045 is the same as the 2034-2035 value.

The investment under Option 1 is a prudent level of investment such that it mitigates all N constraints and addresses sub-transmission, substation and distribution feeder contingency constraints when efficient to do so.

6.3.5 Unquantified benefits

In addition to the quantified benefits, Option 1 has the following unquantified benefits:

- ensures compliance with the NER and EDC, including power factor obligations at transmission connection points;
- provides a more measured approach (compared to Option 2) recognising the general affordability concerns expressed by our customers;
- errs on the side of conservatism while we further evaluate the extreme significant demands being now forecast for South Australia, and the long-term resourcing implications of this work; and
- reduces the rate of workforce scale-up required to deliver our overall capital program.

6.4 Option 2 (Deterministic Case): Planning Criteria

This option uses a deterministic planning approach for the *Sub-Transmission, Substation* and *Distribution Feeder* expenditure categories by applying our Planning Criteria. This approach has been applied to capacity augex for all previous Regulatory Proposals.

The complete list of projects in Option 2 and their associated cost, categorisation and the key driver of investment, is provided in Appendix C.

6.4.1 Description

The key elements of the deterministic planning methodology contained in our Planning Criteria is outlined in Section 3.4.2.2. This option includes several projects dealing with contingency (N-1) conditions on the network, of which a subset have a negative NPV result.

6.4.2 Costs

The capex breakdown over 2025-30 is outlined in Table 12, a summary of all projects included and the inclusion criteria is provided in Table 19:

Table 12: Option 2 Total Capex by Category ($m Jun 2022 Real, excluding network and corporate overheads)

Cost Type	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025 - 30
Sub-transmission Capex	7.57	7.16	13.68	17.61	5.18	**51.20**
Substation Capex	20.31	14.28	18.54	32.57	39.45	**125.15**
Distribution Feeder Capex	2.47	1.43	1.16	3.91	3.98	**12.94**
Connection Point Capex	7.53	9.72	2.10	11.92	19.52	**50.79**
Low Voltage Capex	7.16	7.16	7.16	7.16	7.16	**35.78**
TOTAL	45.04	39.74	42.63	73.17	75.29	**275.86**

Investment under Option 2 results in a recommended spend of $275.9 million in capacity augex. The comparison with the 2020-25 RCP allowance is shown in Figure 11.

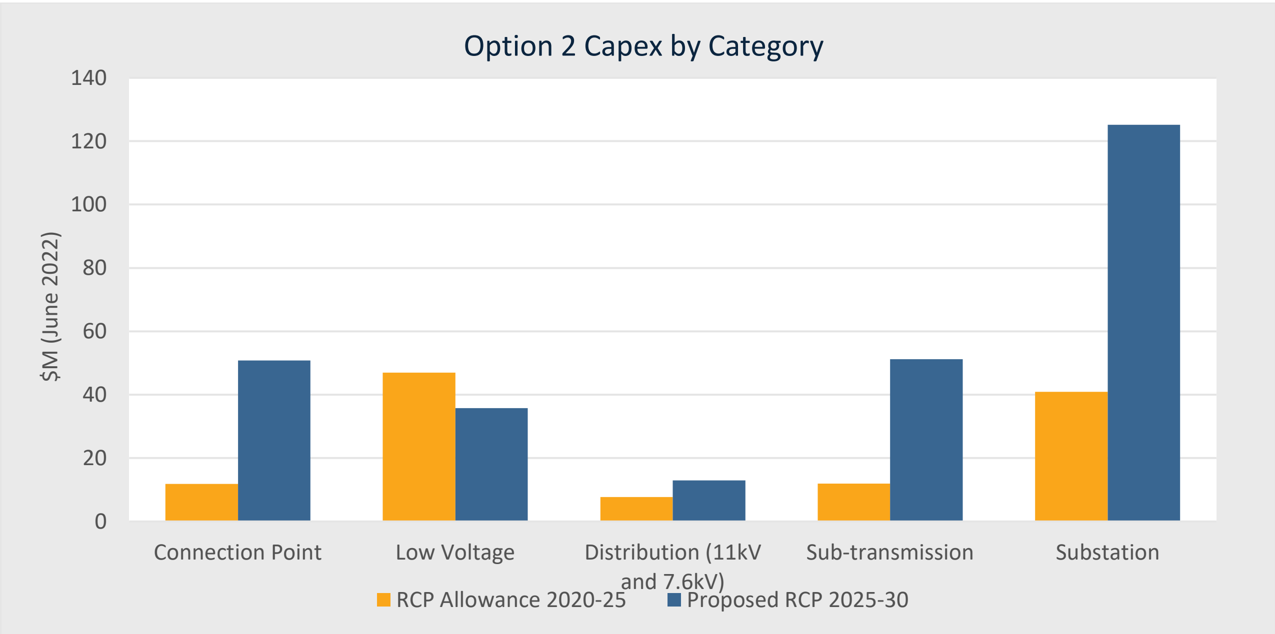

Figure 11: Category capex compared to RCP 2020-25 allowance.

6.4.3 Risks

Table 13 summarises the highest residual risk level in each Risk consequence category from the risk assessment table in Appendix B.

Table 13: Option 2 Risk assessment summary

Risk consequence category	Residual risk level[31]
Performance and Growth - Financial impact	Negligible
Network – Failure to transport electricity from source to load	Low
Customers – Failure to deliver on customer expectations	Low
Overall risk level	Low

In addition to the risk assessment summary, the following risks are associated with Option 2:

- increased cost at a time of affordability challenge for some customers; and
- requires an increased rate of workforce scale-up to deliver our overall capital program.

6.4.4 Quantified benefits

The benefits by expenditure type over the 2025-30 RCP and 2030-35 RCP is outlined in Table 14.

Table 14: Option 2 Benefits by Expenditure Type ($m Jun 2022 Real)

Benefit Type	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025 - 30	2030-31	2031-32	2032-33	2033-34	2034-35*	Total 2025-35
Sub-transmission	0.00	2.92	4.59	10.03	15.29	**32.83**	22.21	31.18	43.02	58.12	76.45	**263.80**
Substation	0.01	0.42	0.72	1.10	2.02	**4.27**	3.15	4.09	5.45	7.30	9.69	**33.96**
Distribution Feeder	0.35	1.11	1.30	1.57	3.41	**7.73**	4.05	4.56	5.12	5.73	6.40	**33.59**
TOTAL	**0.37**	**4.45**	**6.60**	**12.71**	**20.71**	**44.83**	**29.42**	**39.83**	**53.59**	**71.15**	**92.53**	**331.35**

*Note that the annual benefit beyond 2035 up to 2045 is the same as the 2034-2035 value.

6.4.5 Unquantified benefits

In addition to the quantified benefits, Option 2 has the following unquantified benefits:

- ensures compliance with the NER and EDC, including power factor obligations at transmission connection points;
- uses a consistent approach that has been in place since before privatisation to identify investment;
- Planning Criteria provides optimal long-term outcomes for the community, balancing risk and cost;
- adequately recognises HILP events consequence;
- maintains existing emergency backup capability in the network for response to high impact events;
- maintains ability to transfer load under both planned and emergency conditions;
- maintains long term security of supply to current standards;
- could avoid extended outage times for some customers;
- addresses customer expectations[32].

[31] The future level of risk once treatments proposed in this option have been implemented.

[32] Recommendation made by customers as reflected in the People's Panel recommendation, that we invest in security of supply (capacity) consistent with our Planning Criteria in order to maintain current levels of service.

7 Analysis summary and recommended option

This section evaluates the costs, benefits and risks of the three options considered. It includes scenario and sensitivity analysis to test the robustness of the costs and benefits of each option to changing conditions.

7.1 Options assessment

The evaluation of the options identified to meet the need is set out in Table 15 and Figure 12**:**

Table 15: Costs, benefits and risks of options over the 20-year period, $m, $ Jun 2022 real.

Option	Costs		Benefits (PV)[33]	NPV[34]	Risk Level[35]	Ranking
	Capex 25-45[36]	Capex 25-30[37]				
Option 0 (Base Case)	$144.58	$139.86	$125.62	-$3.15	High	3
Option 1 (Hybrid Case)	$225.67	$208.56	$817.24	$618.60	Medium	1
Option 2 (Deterministic Case)	$275.86	$275.86	$825.81	$581.51	Low	2

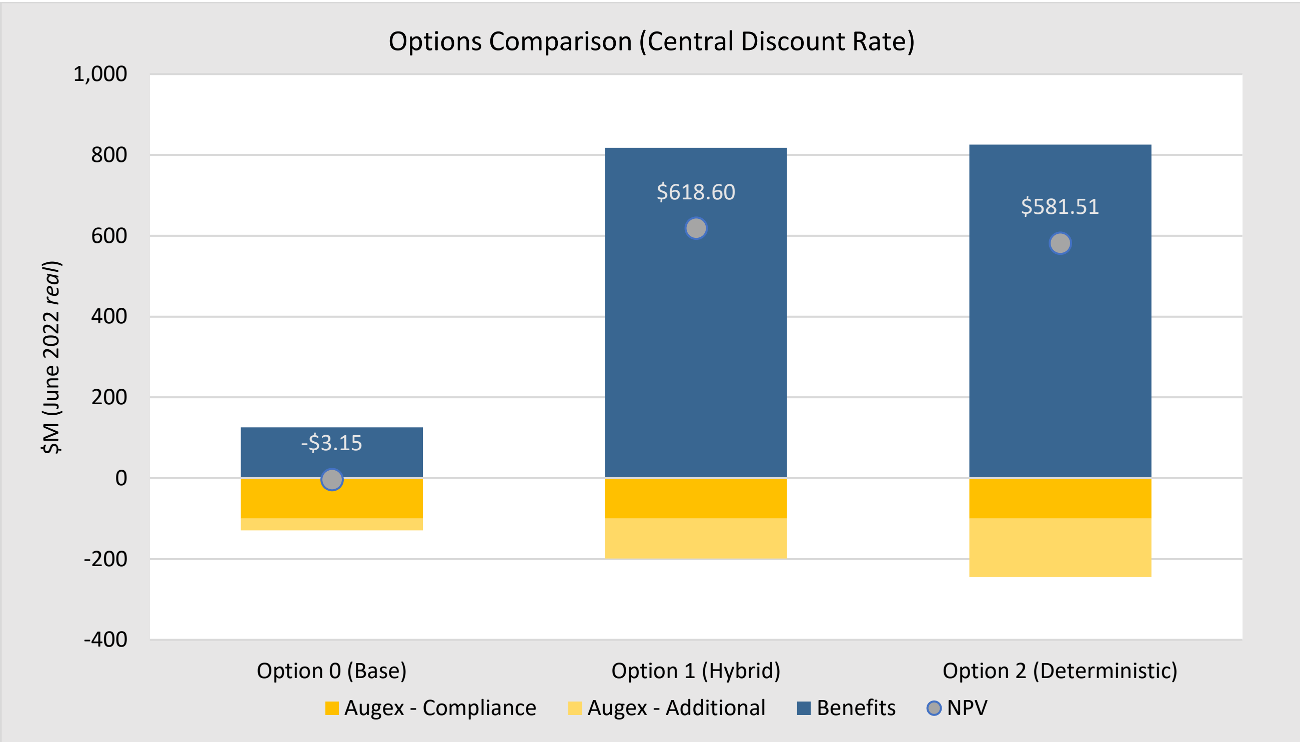

Figure 12: Options Comparison[38]

33 Represents total capital and operating benefits, including any quantified risk reductions over a 20-year cash flow period from 1 July 2025 to 30 June 2045. Benefits are reflected in present value terms at June 2025 at the central discount rate of 4.05%.

34 NPV of the proposal over a 20-year cash flow period from 1 July 2025 to 30 June 2045, based on a discount rate of 4.05%. This calculation does not take into consideration, in option 1, the expenditure of the projects that were deferred to the 2030-35 RCP.

35 The overall risk level for each option after the proposed options are implemented. Refer to Appendix B – Risk Assessment for further details.

36 Represents the total capex associated with the proposed option over a 20-year cash flow period from 1 July 2025 to 30 June 2045.

37 Represents the total capex associated with the proposed option over the regulatory control period from 1 July 2025 to 30 June 2030, excluding corporate overheads.

38 Present value of costs and benefits over 20 years from 2025 to 2045 and are discounted at the central discount rate of 4.05%.

Option 1 defers 15 projects that are included in Option 2 with a combined value of $53.4 million to the 2030-35 RCP.[39] Four of these projects, which amount to $45.3 million are in the substation category. The remaining $8.1 million is across projects in the Subtransmission Network, Distribution Network and SWER Replacement programs. All 13 projects have a negative NPV over 20 years under the central forecasting assumptions. Figure 13 outlines the total cost including deferred projects across all options.

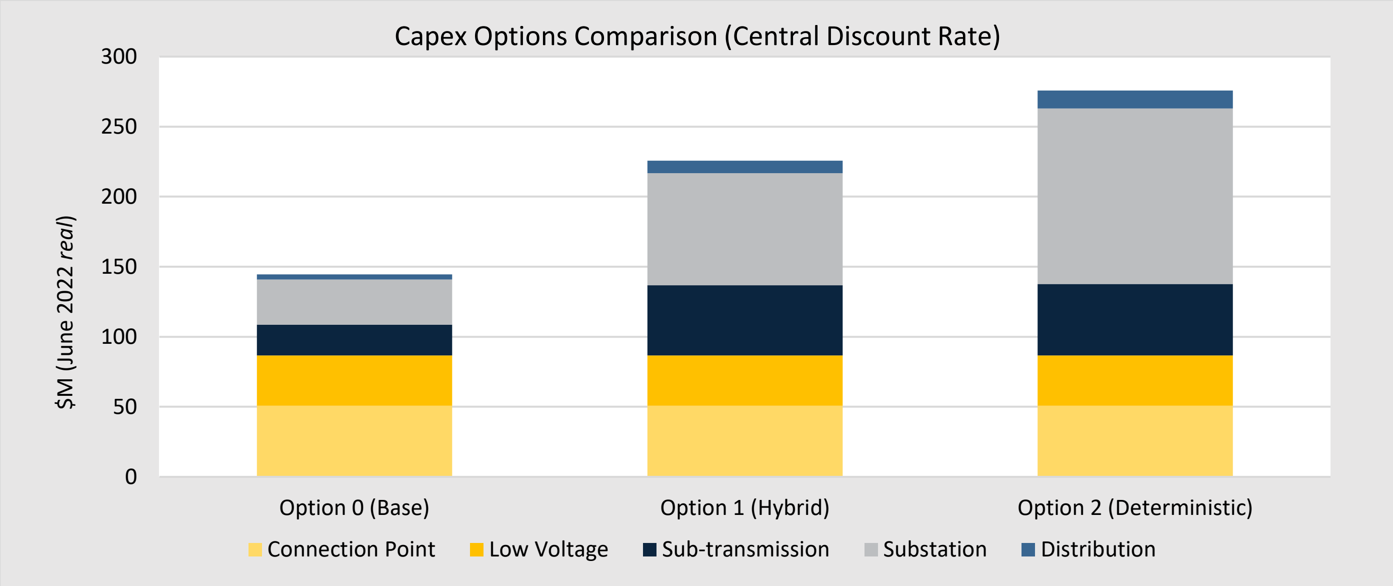

Figure 13: Options Comparison including deferred projects (Central Bound Discount Rate)

[39] This is a deferral of works that our Planning Criteria otherwise indicates would be required.

7.2 Scenario and sensitivity analysis

7.2.1 Variations in the discount rate

To test the sensitivity of the relative net benefits of the options considered, variations in discount rate using an Upper and Lower Bound were also assessed. The NPV and present value of benefits and costs (separately) of the proposal over 20-year cash flow period from 1 July 2025 to 30 June 2045, based on discount rates of 3.50% (Low), 4.05% (Central), and 4.50% (High) is represented in Figure 14. As Figure 14 demonstrates, changes in the discount rate are insufficient to change the number of projects and associated augex in Option 1.

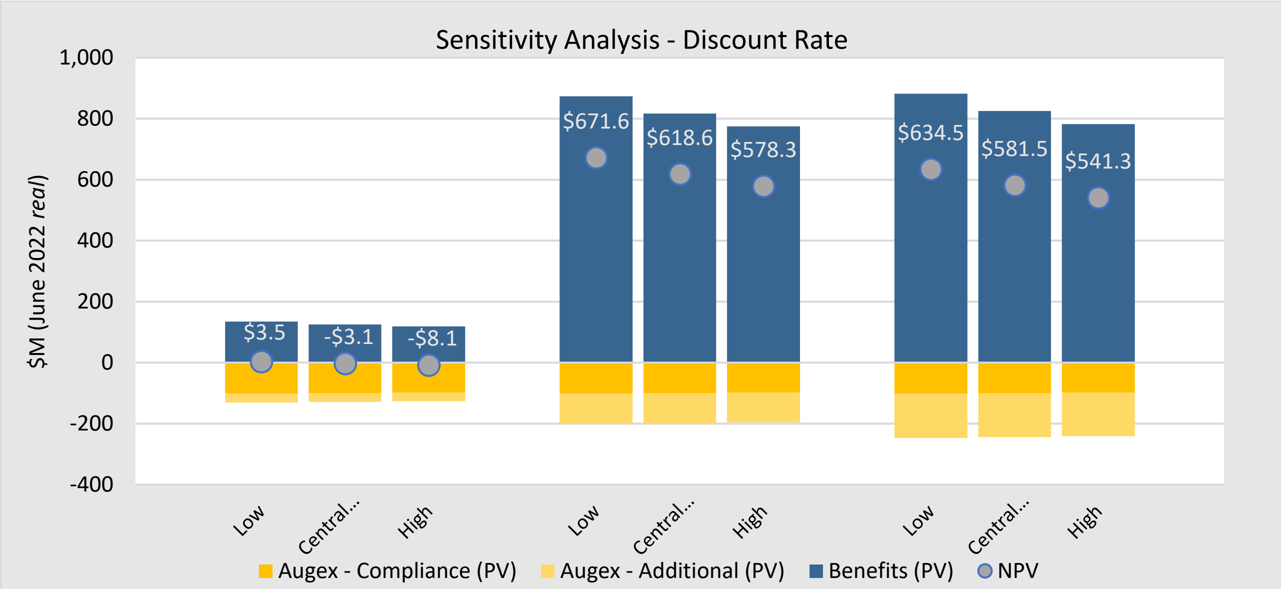

Figure 14: Sensitivities to changes in the discount rate

7.2.2 Variations in the demand growth forecast

A further sensitivity analysis was performed on the three options with respect to NPV, present value of benefits and costs, and undiscounted augex ($ 2022 Real) in 2025-30. Sensitivities were tested against different rates of demand growth, with a high scenario of 120% of the original forecast growth after FY2023 and a low scenario of 80%. A 20% change in growth was deemed appropriate based on the difference between AEMO's Step Change scenario, which forms the central forecast, and AEMO's Reduced Energy Efficiency Sensitivity scenario, which we view as the most realistic of AEMO's other scenarios for demand growth in South Australia. This sensitivity analysis is reflected in Figure 15.

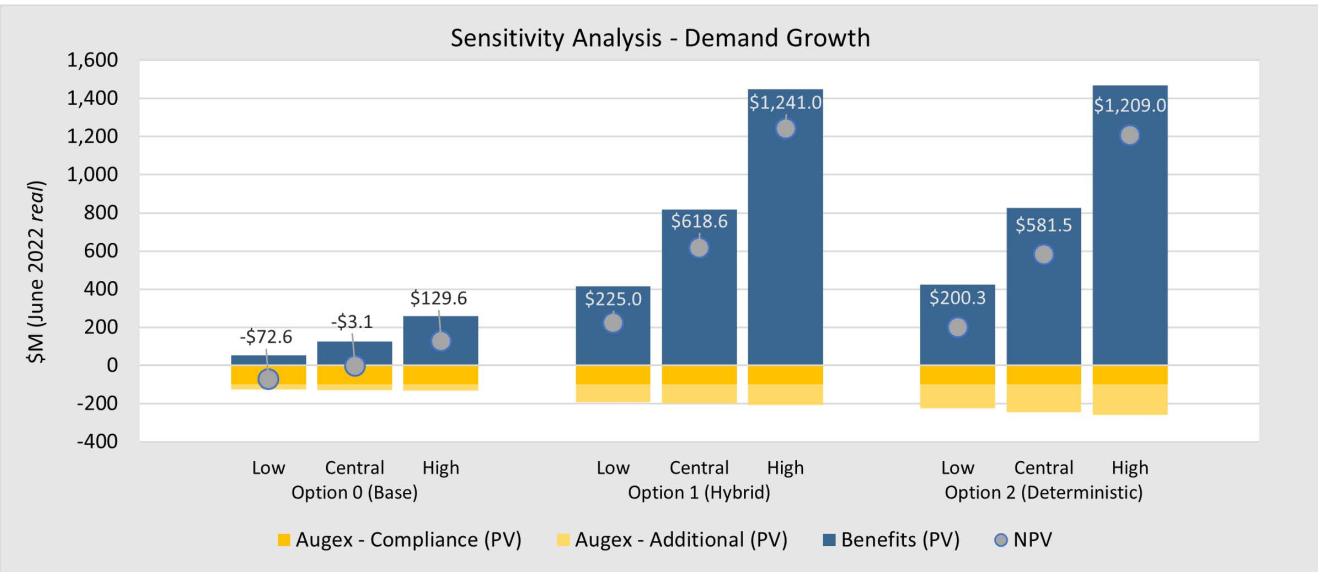

Figure 15: Sensitivities to changes in the demand growth forecast

The change in the demand growth forecast in the sensitivity analysis is sufficient to change the number of projects included and total undiscounted augex associated in all three options, which is reflected in Figure 16 below. The total augex associated with Option 1 during the 25-30 RCP decreases from $208.6 million to $200.7 million under the low growth scenario, and increases to $222.1 million under the high growth scenario.

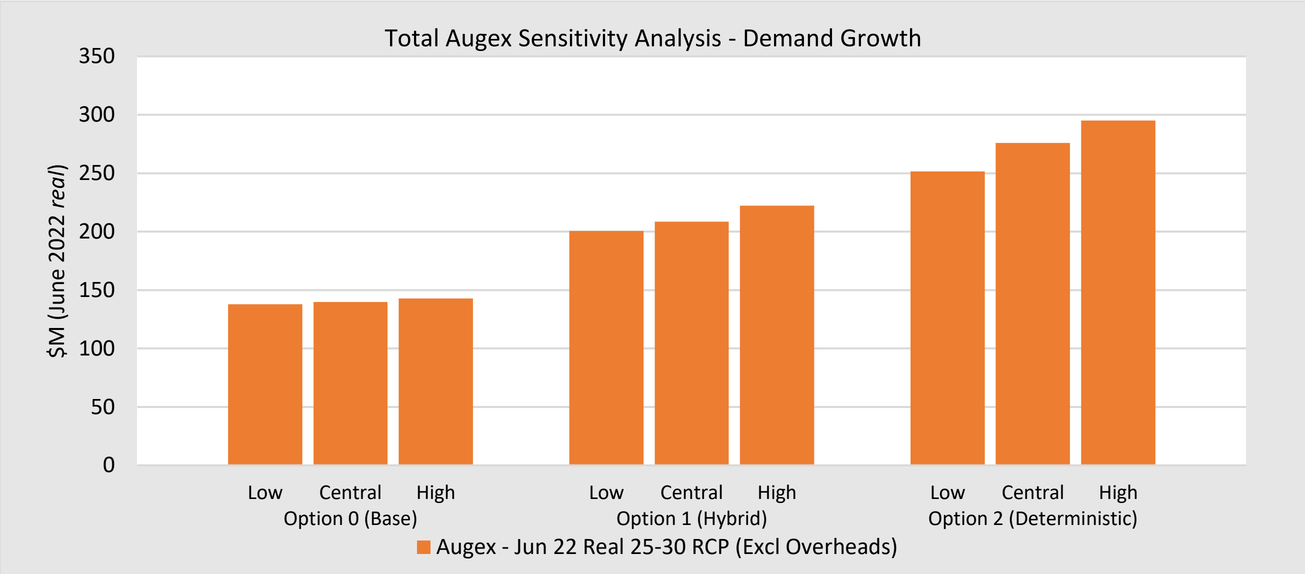

Figure 16: Total Augex Sensitivity to Demand Growth

The $7.9 million reduction in capex under the low growth scenario is due to five projects that were included in Option 1, that would not have been under the low growth scenario, these projects are shown in Table 16 below. Two of these projects are those which are included in Option 1 due to a N constraint under the central PoE 10 forecast that needs to be addressed during the period, but not under the low PoE 10 forecast scenario. The remaining three are projects to address N-1 constraints which are NPV positive under the central demand growth forecast but not under the low forecast.

Although these projects become excluded under a low growth scenario, there is reason to believe this sensitivity is unlikely to eventuate at these network locations. The majority of the costs excluded under this scenario originate in areas with either committed major developments (Virginia), or in established suburbs (particularly Metro South) with consistent observed growth due to infill. For these reasons, these constraints have a high degree of confidence in the central forecast and are unlikely to be subject to a 20% reduction in growth.

Table 16: Projects Excluded From Option 1 Under a Low Growth Scenario

Project	Program	Constraint	Reason for Dropping out of Option 1 Under Low Growth Scenario	Capex - 25-30 RCP ($000s)	Design Year / Construct Year
Seacliff 11kV SM349E Cable Upgrade	Distribution Feeders	Feeder N-1	No longer NPV Positive	$81	2028 / 2029
Virginia sub upgrade	Substation Capacity	Sub N-1	No longer NPV Positive	$6,854	2026 / 2028
New Morphettville Feeder for Oaklands	Substation Capacity	Sub N-1	No longer NPV Positive	$765	2029 / 2030
Birdwood Tee to Birdwood 33kV Line Uprate	Subtransmission Network	Line N	No longer breaches N Constraint - PoE 10	$56	2026 / 2027
Barry Road 11kV Feeder Backbone Restring	Distribution Feeders	Feeder N	No longer breaches N Constraint - PoE 10	$118	2028 / 2029

7.3 Recommended option

In summary, **option 1 (Hybrid Case) is the recommended investment option** on the basis that:

- the **Base Case scenario (Option 0) is not credible** due to the significant levels of unserved energy risk imparted onto our customers. We consider this level of risk to be unacceptable given the high priority attached to security of supply and reliability expressed by our customers via the People's Panel. This option also has a lower net benefit than options 1 and 2 providing the least benefits to our customers;
- **option 2 yields the highest gross benefits and lowest risk** of unserved energy however requires the largest capex. The option includes several projects addressing contingency (N-1) scenarios which have a negative NPV. While we maintain that our Planning Criteria more effectively represents customer's expectations around reliability than the current regulatory framework which relies on the VCR alone, we recognise the need to balance this against affordability concerns; and
- **option 1 has a significantly lower capex than Option 2 and higher NPV** than all other options. This is achieved by tolerating some unmet demand risk that would otherwise be addressed with Option 2. These risks are expected to grow and Option 1 therefore only offers an interim deferral of capex, from the 2025-30 RCP into the following RCP. However, in recognition of our customers' interest in affordability we conclude that Option 1 provides the most balanced outcome in terms of cost, benefits and risk. Importantly, the NPV of Option 1 remains the highest of the three options when subject to a range of sensitivities.

8 Deliverability of recommended option

We have developed a plan to ensure that we can deliver the recommended program of project investments in this business case. 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*.

9 How the recommended option aligns with our consumer and stakeholder engagement

The total expenditure recommended in this business case (Option 1) takes a balanced approach to achieve outcomes that were directly supported by our customers, as ultimately reflected in the recommendations of the People's Panel, whilst meeting the requirements of the capex objectives in the NER. This is noting that:

- the level 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 security of supply (capacity) we undertook a series of deep-dive workshops called 'Focused Conversations' with a broad range of consumer, industry, and government and regulatory body representatives. In these Focused Conversations we sought recommendations on the service outcomes that customers prefer and expect;[40]
- with particular regard to the management of reliability and security of supply (capacity) through network asset augmentation, we engaged on the identified need by outlining:[41]
    - information on our current approach to capacity planning as per our Planning Criteria;
    - our historic spend performance in this area;
    - demand forecasts and the impacts for customers if there is insufficient capacity to meet this demand;
    - consequences for customers if there is insufficient security of supply in the network, particularly to handle HILPs; and
    - our assessment of forecast risks for service performance outcomes to customers;
- in the Focused Conversation we then posed three scenarios of how we could respond to the needs, and expected outcomes for customers in relation to service, expenditure and price, these included:
    - 'basic' – a base case counterfactual of BAU spend only where there is a strict regulatory obligation, but otherwise do-nothing on capacity, to explain the resulting decline in service levels to customers that would result, how system security would be eroded, and how there would be a risk of widespread network security of supply risk that would be managed through load shedding;
    - 'maintain' – a scenario in which we undertake expenditure on investments triggered by our Planning Criteria to maintain current levels of service – maintaining long term security of supply to current standards, and maintain emergency backup capability in the network in response to HILPs;
    - 'new value' – a scenario in which we maintain current levels of security of supply but also use automation to improve supply restoration times, predominantly outer metropolitan areas where are there are alternative supply options; and
    - 'scenario x new value' – a scenario where we go above 'new value' by also increasing security of supply in regional areas (Fleurieu Peninsula and outer metro regions).
- while customers and stakeholders were consistently mindful of energy affordability concerns, Focused Conversations arrived at a clear consensus recommendation to the People's Panel, as the next stage in

[40] This was covered in workshops (1) scene setting / rationale – providing stakeholders with an overview of the factors impacting service outcomes (3) delivering service outcomes through improved reliability, capacity, resilience and bushfire safety – providing stakeholders with information on forecast demand and consequences for customers if there is insufficient network capacity to meet this demand (4) optimising asset investment – summary of focused conversations outcomes and discuss proposed investment levels 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].

[41] See workshop presentation pack: focused conversation – a reliable, resilient and safety electricity network, workshop 3: delivering service outcomes through asset augmentation expenditure, Thursday 5 September 2022. [https://www.talkingpower.com.au]

our engagement program, that we should invest to achieve service outcomes consistent with option 2 ‘maintain’ in order to:

    - maintain current emergency backup capability in the network, for response to HILP events;
    - use the same approach that has been place since before privatisation to identify investment requirements with increasing demand; and
    - maintain long term security of supply to current standards.[42]

- ultimately, the People’s panel deliberated on and affirmed the results of the Focused Conversations in their formal recommendation;
- while we committed to taking this recommendation forward in our Regulatory Proposal, we have also been mindful of the general affordability concerns of our customers and of the general expectation of our customers of ensuring, and the requirement under the NER that proposed expenditures are ultimately efficient and prudent. Therefore, subsequent to our engagement program, we modelled a further investment option to identify only those investments in capacity augex that can be proved as efficient using a purely economic / probabilistic approach – reflected in this business case as the recommended option 1.[43] Our view is that this option takes a balanced, or more measured, approach to aligning to the outcomes recommended by our customers on the basis that:

    - it will maintain current levels of service over the 2025-30 RCP;
    - align the approximate level of expenditure reflected in the recommendation of the People’s Panel;
    - ensure we can meet our compliance obligations; but
    - with the exception that it is unlikely to support long term security of supply in the network.

Since conducting the People’s Panel, 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 respect to this Maintain Underlying Reliability Performance Program, noting that:

- members of the People’s Panel affirmed that their recommendations, including in respect of security of supply / capacity expenditure as set out in this business case, remain current;[44]
- some parties such as that from South Australian Council of Social Service (**SACOSS**)[45] and the South Australian Government Department of Energy and Mining[46] generally urged further consideration of the overall magnitude of our forecast capital expenditure across in totality. However, at the same time SACOSS noted that it supports maintaining current reliability levels and efforts driven by compliance; and
- DEM considered that we should identify savings on our capacity augmentation expenditure and sought further information on why these needs should apply in the 2025-30 period – our business case now provides that full justification for the expenditure, and by taking a hybrid planning approach, has sought to take a more measured and economic benefits based approach to our forecast.[47]

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[42] The recommendations of the Focused Conversations are contained in documents published on our TalkingPower website under the page titled ‘focused conversations’. SA Power Networks, final outputs and recommendations to the People’s Panel for security of supply (capacity), October 2022. Accessible on: [https://www.talkingpower.com.au].

[43] At the time of our engagement program we also had insufficient information on demand forecasting and constraint analysis to apply to a probabilistic approach.

[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.

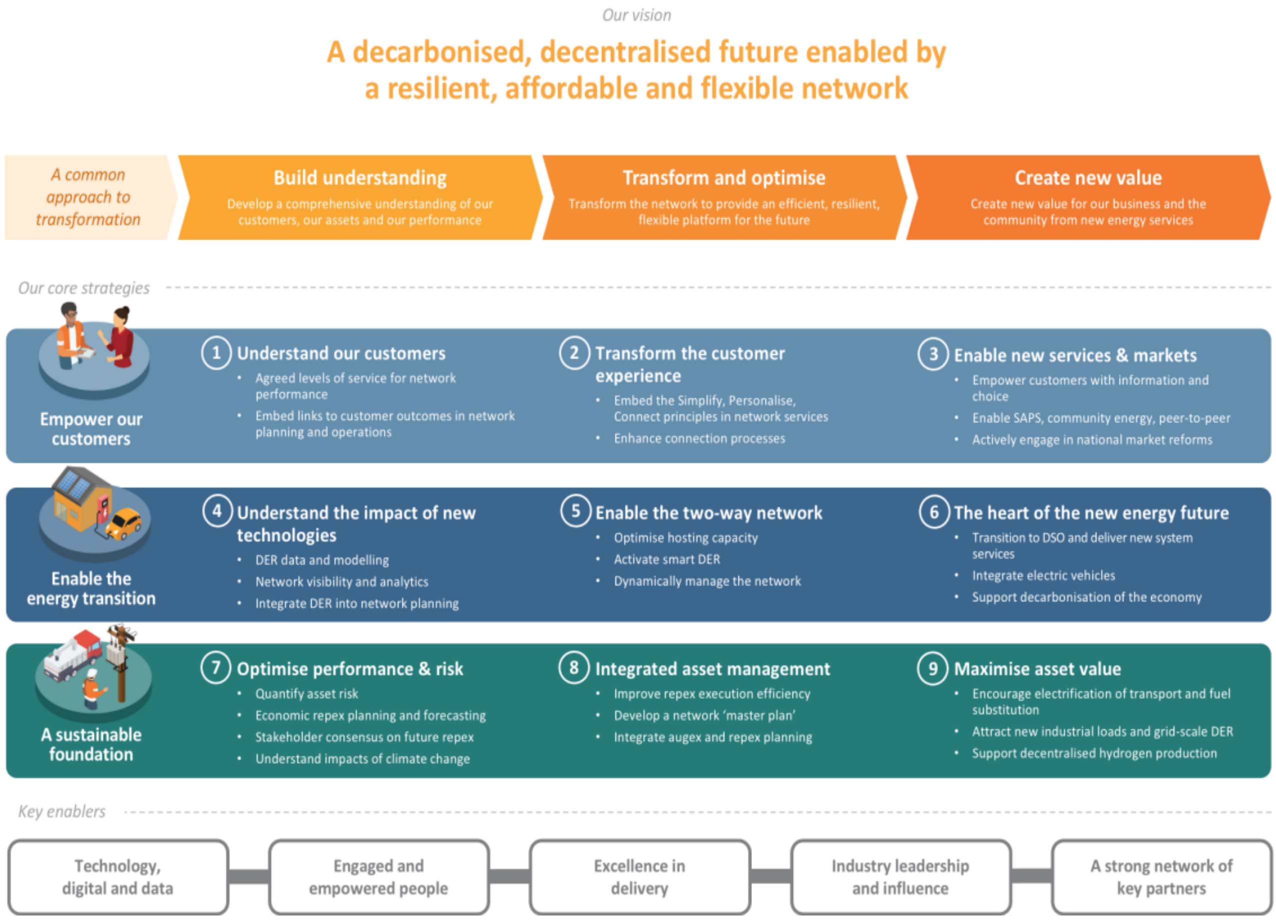
[47] DEM, South Australian Department of Energy and Mining – Submission, October 2023.

10 Alignment with our vision and strategy

This business case proposes expenditure to ensure sufficient network capacity to meet and manage expected customer demand for service and compliance with our regulatory obligations, is aligned to progress our overall company 'Network Strategy' and our vision within this strategy, displayed in Figure 17 below. This is noting that the expenditure in this business case is aligned to several of the core strategies within the Network Strategy as follows:

- 'empower of 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 trade-off's;
- 'optimise performance and risk':
  - the program's use of probabilistic analysis within the broader construct of our Planning Criteria, reflects our strategic desire of improving our approaches by which to quantify asset risk of customers, take an economic approach to our forecasting of network needs; and
  - the program provides an outcome for customers that is not only efficient but also ensures a stable foundation over the 2025-30 RCP at least, in light of increasing electrification and potential emerging effects of climate change, by having involved an assessment of customer benefits and risk (were the program to not proceed) and by seeking to ensure that service performance is maintained at current levels.

Figure 17 SA Power Networks' Network Strategy on a page



Appendix A –Assumptions

A.1 Assumptions

The following assumptions have been made in determining the NPV:

- **Discount Rate:**
    - A Central Discount Rate of 4.05% has been used.
    - A lower bound of 3.5% and upper bound of 4.5% were considered in the sensitivities in Section 7.2.1.
- **Demand Forecast:**
    - Central AEMO growth scenario has been used. This is the most likely scenario.
    - Both options use 10% PoE and 50% PoE to identify constraints.
    - Where a 10% PoE or 50% PoE forecast is not available, this forecast is estimated based on a 10% PoE to 50% PoE ratio of 1.10.
- **Avoided involuntary load shedding:**
    - Involuntary load shedding occurs when a customer's load is interrupted from the network without warning or their agreement. This can occur due to unavailability of network elements and the resulting reduction in network capacity to supply the load.
    - The unserved energy (**USE**) is the probability weighted average amount of load that customers request to utilise but would need to be involuntarily curtailed due to loss of network connectivity or a network capacity limitation. We forecast load over the assessment period and has quantified the USE by comparing forecast load to network capabilities under normal (N) and contingency (N-1) conditions. A reduction in involuntary load shedding results in a positive contribution to market benefits of the credible option being assessed.
    - The market benefit that results from reducing the involuntary load shedding with a network solution is estimated by multiplying the quantity of USE in MWh by the VCR. The VCR is measured in dollars per MWh and is used as proxy to evaluate the economic impact of USE on customers.
    - VCR has been calculated on a site-specific basis for each constraint based on the affected customer type and locality, with values based on the 2022 VCR Annual Adjustment[48].
    - Although the assessment period for the economic analysis is 20 years, the amount of additional USE per year does not grow beyond the 10th year.
- **Load Duration Curve:**
    - Load duration curves have been calculated using 5 years of measured data (2017-2022) for each specific project. The underlying demand (without CER) has been estimated using site-specific solar PV estimations applied to the time series data. As such, the resulting load duration curves reflect a 5-year period of underlying demand.
    - USE is derived by applying the ratio of the constraint rating against the forecast peak to the normalised load duration curve.
- **Load shedding forecast scenarios**
    - For all constraints where avoided load shedding is modelled, the value of USE is determined under both 10% PoE and 50% PoE conditions. The resulting value of USE is apportioned based on the following ratios:

	Forecast Proportions
10% PoE	0.3
50% PoE	0.7

[48] AER, VCR Update Annual Adjustment, 2022 available on aer.gov.au.

- **Likelihood of Failure:**
  - Feeder exit failure rates are derived based on historic failures of both feeder exit cables and feeder circuit breakers. This is calculated based on the following:
    - Number of faults (2010-2022) = 97 = 7.46 faults per year
    - Number of feeder exits = 657
    - Feeder CB Failure Rate = 0.0033

$$Fault\ Rate\ (pa)_{Feeder\ Exit} = \frac{Faults\ (pa)}{No\ of\ feeder\ exits} + CB\ Failure\ Rate = 0.0147$$

  - A simplified 66kV overhead line faults per km per annum factor is used to estimate the expected likelihood of an unplanned 66kV line outage upon critical sections of sub-transmission lines, as outlined in the table below:

	Overhead	**Underground**
Metro 66kV	0.011	0.010
Country 66kV	0.006	N/A
33kV	0.048	0.014

  - For both SA Power Networks and ElectraNet substation transformers, a fault rate of 0.02 pa has been used. This reflects a one in 50-year failure rate.

- **Distribution Loss Factor:**
  - A distribution loss factor (DLF) is applied to the estimated USE to account for network losses.
  - For all constraints, a DLF of 1.107 is used. This reflects the published SA Power Networks 2022/23 DLF for low voltage small customers.

A.2 Capex categories relating to categories identified in the regulatory template

We considered if the drivers for investment are categorised as reinforcement or greenfield. Our recommended option represents $40 million (18%) in greenfield infrastructure and $188 million (82%) in reinforcement infrastructure.

Greenfield investment entails expanding our network, primarily in response to population relocation to areas that were previously unoccupied. This type of investment includes the establishment of new zone substations, as well as new sub-transmission lines or feeders where assets did not previously exist.

Reinforcement investment involves upgrading or interconnecting existing network infrastructure to meet the energy needs of customers. This includes infill or upgrades that extend or increase the capacity to supply customers from an existing zone substation. Examples of this type of investment include infrastructure necessary to support developments in Bowden, Cheltenham, and Tonsley.

Appendix B – Risk Assessment

Table 17: Risk Matrix

Consequence \ Likelihood	1	2	3	4	5
1	Negligible	Negligible	Low	Low	Medium
2	Negligible	Low	Low	Medium	High
3	Low	Low	Medium	High	High
4	Low	Medium	High	High	Extreme
5	Medium	High	High	Extreme	Extreme

Table 18: Risk Assessment

				Current risk (Option 0)			Residual risk (Option 1)			Residual risk (Option 2)		
ID	**Risk scenario**	**Consequence description**	**Consequence category**	**Consequence**	**Likelihood**	**Risk Level**	**Consequence**	**Likelihood**	**Risk Level**	**Consequence**	**Likelihood**	**Risk Level**
1	Sub-transmission	Large amounts of unserved energy. Heavily constrains new or growth of large load connections -particularly in metropolitan areas.	**Performance and Growth** – Financial Impact	2	5	High	2	2	Low	1	2	Negligible
		Significant involuntary load shedding required to mitigate against infrastructure overloads. Contingent (N-1) events result in widespread interruptions.	**Network** – Failure to transport electricity from source to load	3	5	High	4	2	Medium	3	2	Low
		Possible widespread customer dissatisfaction, negative media coverage and long-term reputational harm.	**Customers** – Failure to deliver on customer expectations	3	5	High	2	2	Low	2	2	Low

ID	Risk scenario	Consequence description	Consequence category	Current risk (Option 0) Consequence	Likelihood	Risk Level	Residual risk (Option 1) Consequence	Likelihood	Risk Level	Residual risk (Option 2) Consequence	Likelihood	Risk Level
2	Substation	Multiple, moderately sized areas of network capacity limitations. Likely disruption to high growth centres.	**Performance and Growth** – Financial Impact	1	5	Medium	1	3	Low	1	2	Negligible
		Frequent involuntary load shedding. Contingent (N-1) events result in extended reduced capacity and further involuntary load shedding.	**Network** – Failure to transport electricity from source to load	2	5	High	2	2	Low	2	2	Low
		Customer communities feeling victimised by localised poor network performance.	**Customers** – Failure to deliver on customer expectations	3	5	High	3	2	Low	3	2	Low
3	Distribution	Localised unserved energy. More concentrated and severe limits to customer growth.	**Performance and Growth** – Financial Impact	2	5	High	2	3	Low	1	2	Negligible
		Less redundancy at this network level results in sustained load shedding.	**Network** – Failure to transport electricity from source to load	2	5	High	1	3	Low	1	2	Negligible
		Likely most common network area for customer dissatisfaction but with least impact to reputation or brand.	**Customers** – Failure to deliver on customer expectations	2	5	High	2	3	Low	1	2	Negligible
			Overall Risk Level[49]			High			Medium			Low

[49] For each option, the overall risk level is the highest of the individual risk levels.

Appendix C – Project Summary

Table 19: Summary of Projects Included (Across Options 1, 2 & 3)

			Capex - 25-30 RCP ($k)			Design Year / Construct Year		
Project	**Constraint**	**Criteria for Inclusion[50]**	**Option 0**	**Option 1**	**Option 2**	**Option 0**	**Option 1**	**Option 2**
Connection Point								
AUG001: Connection Point Capacity Augmentation (ETC/NER) - Resulting from ElectraNet Works								
Mannum Connection Point Upgrade	ENET TF replacement	Mandatory	$7,388	$7,388	$7,388	2025 / 2026	2025 / 2026	2025 / 2026
Tailem Bend 33kV CP Upgrade and Segregation	ENET Upgrade	Mandatory	$6,695	$6,695	$6,695	2028 / 2029	2028 / 2029	2028 / 2029
Mount Gambier CP Upgrade	ENET Upgrade	Mandatory	$1,361	$1,361	$1,361	2028 / 2029	2028 / 2029	2028 / 2029
Willunga 66kV Reactor	Metro South Power Factor	Mandatory	$3,267	$3,267	$3,267	2026 / 2027	2026 / 2027	2026 / 2027
Victor Harbor 11kV Reactors	Metro South Power Factor	Mandatory	$1,588	$1,588	$1,588	2025 / 2026	2025 / 2026	2025 / 2026
Salisbury 11kV Reactors	Metro North Power Factor	Mandatory	$1,588	$1,588	$1,588	2027 / 2028	2027 / 2028	2027 / 2028
Morphett Vale East 66kV Reactor	Metro South Power Factor	Mandatory	$3,448	$3,448	$3,448	2028 / 2029	2028 / 2029	2028 / 2029
Renmark 11kV Reactor	Berri Power Factor	Mandatory	$1,588	$1,588	$1,588	2029 / 2030	2029 / 2030	2029 / 2030
Magill 66kV Reactor	Metro East Power Factor	Mandatory	$3,448	$3,448	$3,448	2026 / 2027	2026 / 2027	2026 / 2027
Northfield 66kV Reactor	Metro East Power Factor	Mandatory	$3,448	$3,448	$3,448	2029 / 2030	2029 / 2030	2029 / 2030
Norwood 66kV Reactor	Metro East Power Factor	Mandatory	$3,448	$3,448	$3,448	2028 / 2029	2028 / 2029	2028 / 2029
Port Noarlunga 66kV Reactor	Metro South Power Factor	Mandatory	$3,448	$3,448	$3,448	2029 / 2030	2029 / 2030	2029 / 2030
Cheltenham 66kV Reactor	Metro West Power Factor	Mandatory	$3,448	$3,448	$3,448	2029 / 2030	2029 / 2030	2029 / 2030
Balhannah 66kV Reactor	Mount Barker Power Factor	Mandatory	$3,176	$3,176	$3,176	2025 / 2026	2025 / 2026	2025 / 2026
Elizabeth South 66kV Reactor	Metro North Power Factor	Mandatory	$3,448	$3,448	$3,448	2028 / 2029	2028 / 2029	2028 / 2029
	Subtotal		**$50,788**	**$50,788**	**$50,788**			
Low Voltage								
AUG002: LV & Distribution Transformers (QoS BAU) - LV augmentation expenditure (unrelated to reverse power flows)								
LV & Distribution Transformers	N/A	Mandatory	$24,192	$24,192	$24,192	2025 / 2030	2025 / 2030	2025 / 2030

[50] 'Mandatory' projects include base augmentation expenditure, projects which address an N constraint under the PoE 50 forecast, the Connection Point and Low Voltage categories. This is discussed in further detail under Section 5.2.

			Capex - 25-30 RCP ($k)			Design Year / Construct Year		
Project	**Constraint**	**Criteria for Inclusion[50]**	**Option 0**	**Option 1**	**Option 2**	**Option 0**	**Option 1**	**Option 2**
AUG010: LV & Distribution Transformers (QoS BAU) - LV augmentation expenditure (unrelated to reverse power flows)								
LV Two Way Network	N/A	Mandatory	$11,587	$11,587	$11,587	2025 / 2030	2025 / 2030	2025 / 2030
	Subtotal		**$35,779**	**$35,779**	**$35,779**			
Distribution (11kV and 7.6 kV)								
AUG003: Distribution Feeder (11 & 7.6kV) Capacity Augmentation								
New Wallaroo Feeder	Feeder N-1	Planning Criteria	-	-	$500	-	-	2025 / 2025
Trott Park Feeder Backbone Restring	Feeder N	N Constraint - PoE 50	$266	$266	$266	2025 / 2026	2025 / 2026	2025 / 2026
Victor Harbor East (VH12) Feeder Tie Restring	Feeder N-1	Planning Criteria	-	-	$829	-	-	2028 / 2029
Aldenhoven Feeder (NL111D) Restring	Feeder N-1	Planning Criteria	-	-	$1,042	-	-	2026 / 2027
Loxton LX43 Feeder Survey T80 + cable upgrade	Feeder N-1	Planning Criteria	-	-	$94	-	-	2025 / 2025
Clapham 11kV Feeder Backbone Restring	Feeder N	N Constraint - PoE 10	-	$19	$19	-	2027 / 2028	2027 / 2028
Barry Road 11kV Feeder Backbone Restring	Feeder N	N Constraint - PoE 10	-	$118	$118	-	2028 / 2029	2028 / 2029
SA14 N Overload	Feeder N	N Constraint - PoE 10	-	$91	$91	-	2025 / 2026	2025 / 2026
Fawnbrake 11kV Feeder Backbone Upgrade	Feeder N-1	Planning Criteria	-	-	$206	-	-	2025 / 2025
New 11kV Feeder from Kilburn Substation	Feeder N-1	Planning Criteria	-	-	$438	-	-	2025 / 2025
Ridleyton 11kV Feeder Backbone Upgrade	Feeder N	N Constraint - PoE 50	$138	$138	$138	2025 / 2025	2025 / 2025	2025 / 2025
Emmerson Drive 11kV NL115F Restring	Feeder N-1	Planning Criteria, NPV>0	-	$179	$179	-	2028 / 2029	2028 / 2029
Somerton Park 11kV SM410D Restring	Feeder N-1	Planning Criteria, NPV>0	-	$248	$248	-	2028 / 2029	2028 / 2029
Oaklands 11kV Feeder Exit Load Switches	Unable to isolate 11kV feeder exit cables	Mandatory	$88	$88	$88	2028 / 2029	2028 / 2029	2028 / 2029
Tapleys Hill 11kV NL210B Cable Replacement	Feeder N-1	Planning Criteria, NPV>0	-	$152	$152	-	2028 / 2029	2028 / 2029
Diagonal Road 11kV SM216F Restring	Feeder N-1	Planning Criteria, NPV>0	-	$61	$61	-	2028 / 2029	2028 / 2029
Glenelg 11kV SM410B Cable Replacement	Feeder N-1	Planning Criteria, NPV>0	-	$28	$28	-	2028 / 2029	2028 / 2029
Brownhill 11kV SM411C Restring	Feeder N-1	Planning Criteria, NPV>0	-	$17	$17	-	2029 / 2030	2029 / 2030
Westbourne Park 11kV SM179A Restring	Feeder N-1	Planning Criteria, NPV>0	-	$220	$220	-	2029 / 2030	2029 / 2030
North Plympton 11kV ME131E Restring	Feeder N-1	Planning Criteria	-	-	$138	-	-	2029 / 2030
St Marys 11kV SM402D Restring	Feeder N-1	Planning Criteria, NPV>0	-	$130	$130	-	2029 / 2030	2029 / 2030

Project	Constraint	Criteria for Inclusion[50]	Capex - 25-30 RCP ($k)			Design Year / Construct Year		
			Option 0	Option 1	Option 2	Option 0	Option 1	Option 2
Encounter Bay VH10-Victor Harbor West VH16 11kV Restring	Feeder N-1	Planning Criteria, NPV>0	-	$59	$59	-	2028 / 2029	2028 / 2029
Town Centre VH11-Victor Harbor West VH16 11kV Restring	Feeder N-1	Planning Criteria, NPV>0	-	$14	$14	-	2028 / 2029	2028 / 2029
Urimbirra VH15-Inman Valley VH17 11kV Restring	Feeder N-1	Planning Criteria	-	-	$83	-	-	2026 / 2027
Victor Harbor West VH16-Inman Valley VH17 Restring	Feeder N-1	Planning Criteria, NPV>0	-	$83	$83	-	2028 / 2029	2028 / 2029
Goolwa 11kV Feeder Exit Load Switches	Unable to isolate 11kV feeder exits	Mandatory	$29	$29	$29	2029 / 2030	2029 / 2030	2029 / 2030
New Happy Valley 11kV Feeder	Feeder N-1	Planning Criteria, NPV>0	-	$3,346	$3,346	-	2028 / 2029	2028 / 2029
New Morphettville Substation 11kV Feeder	Feeder N-1	Planning Criteria	-	-	$688	-	-	2028 / 2029
Seacliff 11kV SM349E Cable Upgrade	Feeder N-1	Planning Criteria, NPV>0	-	$81	$81	-	2028 / 2029	2028 / 2029
Intertrip Pedlar Creek gen on Ochre 11kV NL544B	Feeder N-1	Planning Criteria, NPV>0	-	$100	$100	-	2028 / 2029	2028 / 2029
Loxton West LX51 11kV survey & upgrade	Feeder N-1	Planning Criteria, NPV>0	-	$196	$196	-	2025 / 2025	2025 / 2025
MTB52 Oakbank Line Upgrade	Feeder N	N Constraint - PoE 10	-	$89	$89	-	2025 / 2025	2025 / 2025
AUG007: Distribution Line SWER Capacity Augmentation								
SWER Replacements	N/A	Mandatory	-	-	$3,176	2030 / 2035	2030 / 2035	2025 / 2030
	Subtotal		**$521**	**$5,750**	**$12,942**			
Substation								
AUG004: Strategic Network Capacity (Other) - Labour capitalization for long term planning and network architecture								
Design Work 2025	N/A	Mandatory	$2,722	$2,722	$2,722	2025 / 2025	2025 / 2025	2025 / 2025
Design Work 2026	N/A	Mandatory	$2,722	$2,722	$2,722	2025 / 2026	2025 / 2026	2025 / 2026
Design Work 2027	N/A	Mandatory	$2,722	$2,722	$2,722	2026 / 2027	2026 / 2027	2026 / 2027
Design Work 2028	N/A	Mandatory	$2,722	$2,722	$2,722	2027 / 2028	2027 / 2028	2027 / 2028
Design Work 2029	N/A	Mandatory	$2,722	$2,722	$2,722	2028 / 2029	2028 / 2029	2028 / 2029
Design Work 2030	N/A	Mandatory	$2,722	$2,722	$2,722	2029 / 2030	2029 / 2030	2029 / 2030
AUG005: Substation Capacity Augmentation								
Virginia sub upgrade	Sub N-1	Planning Criteria, NPV>0	-	$6,854	$6,854	-	2026 / 2028	2026 / 2028
Hackham sub upgrade	Sub N-1	Planning Criteria	-	-	$7,899	-	-	2025 / 2026

Project	Constraint	Criteria for Inclusion[50]	Capex - 25-30 RCP ($k) Option 0	Capex - 25-30 RCP ($k) Option 1	Capex - 25-30 RCP ($k) Option 2	Design Year / Construct Year Option 0	Design Year / Construct Year Option 1	Design Year / Construct Year Option 2
Nairne sub upgrade	Sub N	N Constraint - PoE 10	-	$4,595	$4,595	-	2027 / 2028	2027 / 2028
Northfield sub upgrade	Sub N	N Constraint - PoE 50	$8,172	$8,172	$8,172	2026 / 2027	2026 / 2027	2026 / 2027
Mount Barker East new sub	Feeder N	N Constraint - PoE 10	-	$4,131	$16,523	-	2029 / 2031	2028 / 2030
Gawler East new sub	Feeder N	N Constraint - PoE 10	-	-	$14,396	-	-	2028 / 2029
Smithfield West sub upgrade	Sub N-1	Planning Criteria, NPV>0	-	$6,738	$6,738	-	2025 / 2026	2025 / 2026
Kingston SE sub upgrade	Sub N	N Constraint - PoE 10	-	$1,520	$1,520	-	2025 / 2025	2025 / 2025
New Morphettville Feeder for Ascot Park	Sub N-1	N Constraint - PoE 10	-	$685	$685	-	2025 / 2026	2025 / 2026
Portee sub upgrade	Sub N	N Constraint - PoE 50	$1,808	$1,808	$1,808	2025 / 2026	2025 / 2026	2025 / 2026
Maslins new sub	Sub N-1	Planning Criteria	-	-	$17,001	-	-	2028 / 2029
Mount Burr sub upgrade	Sub N	N Constraint - PoE 50	$392	$392	$392	2025 / 2025	2025 / 2025	2025 / 2025
New Morphettville Feeder for Oaklands	Sub N-1	Planning Criteria, NPV>0	-	$765	$765	-	2029 / 2030	2029 / 2030
Kalangadoo sub upgrade	Sub N	N Constraint - PoE 50	$835	$835	$835	2025 / 2025	2025 / 2025	2025 / 2025
Qualco sub upgrade	Sub N	N Constraint - PoE 10	-	$2,477	$2,477	-	2026 / 2027	2026 / 2027
Port Hughes new Sub	Sub N-1	Planning Criteria	-	-	$5,976	-	-	2027 / 2028
Square Waterhole new Sub	Sub N-1	Planning Criteria, NPV>0	-	$6,984	$6,984	-	2029 / 2030	2029 / 2030
Lyndoch Substation Cable Replacements	Permanent cable installations required	Mandatory	$699	$699	$699	2029 / 2030	2029 / 2030	2029 / 2030
FS Prelim Design - Substation Capacity 2025	N/A	Mandatory	$45	$45	$136	2025 / 2030	2025 / 2030	2025 / 2025
FS Prelim Design - Substation Capacity 2026	N/A	Mandatory	$45	$45	$136	2025 / 2031	2025 / 2031	2025 / 2026
FS Prelim Design - Substation Capacity 2027	N/A	Mandatory	$45	$45	$136	2026 / 2032	2026 / 2032	2026 / 2027
FS Prelim Design - Substation Capacity 2028	N/A	Mandatory	$45	$45	$136	2027 / 2033	2027 / 2033	2027 / 2028
FS Prelim Design - Substation Capacity 2029	N/A	Mandatory	$45	$45	$136	2028 / 2034	2028 / 2034	2028 / 2029
FS Prelim Design - Substation Capacity 2030	N/A	Mandatory	$45	$45	$136	2029 / 2035	2029 / 2035	2029 / 2030
AUG008: Voltage Regulation - To maintain QoS within NER requirements								
Spalding 11kV Sub + Regulator Upgrade	Reg N	N Constraint - PoE 10	-	$423	$423	2026 / 2027	2026 / 2027	2026 / 2027
AUG009: Land - Substation capacity augmentation								
Land	N/A	Mandatory	$3,259	$3,259	$3,259	2026 / 2029	2026 / 2029	2026 / 2029

			Capex - 25-30 RCP ($k)			Design Year / Construct Year		
Project	**Constraint**	**Criteria for Inclusion[50]**	**Option 0**	**Option 1**	**Option 2**	**Option 0**	**Option 1**	**Option 2**
	Subtotal		**$31,771**	**$66,941**	**$125,148**			
Sub-transmission								
AUG006: Subtransmission Capacity Augmentation								
East Tce-Norwood 66kV Line upgrade	Line N-1	Planning Criteria, NPV>0	-	$1,741	$1,741	-	2025 / 2026	2025 / 2026
Clarence Gardens-Tee new 66kV line	Line N-1	Planning Criteria, NPV>0	-	$9,014	$9,014	-	2027 / 2028	2027 / 2028
North Unley - Whitmore Square 66kV line uprate	Line N-1	Planning Criteria, NPV>0	-	$476	$476	-	2025 / 2026	2025 / 2026
Athol Park-Woodville new 66kV line	Line N-1	Planning Criteria, NPV>0	-	$14,677	$14,677	-	2026 / 2028	2026 / 2028
Hatherleigh-Robe #2 33kV line	Line N	N Constraint - PoE 50	$12,555	$12,555	$12,555	2028 / 2029	2028 / 2029	2028 / 2029
Angle Vale - Virginia Meshing	Line N-1	Planning Criteria, NPV>0	-	$2,336	$2,336	-	2027 / 2028	2027 / 2028
Penola Tee to Penola Line Uprate	Line N	N Constraint - PoE 50	$703	$703	$703	2025 / 2025	2025 / 2025	2025 / 2025
Freeling to Kapunda 33kV line uprate	Line N	N Constraint - PoE 50	$507	$507	$507	2025 / 2026	2025 / 2026	2025 / 2026
Birdwood Tee to Birdwood 33kV Line Uprate	Line N	N Constraint - PoE 10	-	$56	$56	-	2026 / 2027	2026 / 2027
Waterloo to Riverton Tee 33kV Line Upgrade	Line N	N Constraint - PoE 50	$924	$924	$924	2025 / 2026	2025 / 2026	2025 / 2026
Pinnaroo 3MVAr StatCom Project	Line N	N Constraint - PoE 50	$2,995	$2,995	$2,995	2025 / 2026	2025 / 2026	2025 / 2026
Burnside New 11kV Feeder	Line N-1	Planning Criteria	-	-	$899	-	-	2028 / 2029
Southern Outer Metro 66kV restring loop	Line N-1	Commenced	$3,050	$3,050	$3,050	2025 / 2025	2025 / 2025	2025 / 2025
FS Prelim Design - Line Capacity 2025	N/A	Mandatory	$45	$45	$136	2025 / 2030	2025 / 2030	2025 / 2025
FS Prelim Design - Line Capacity 2026	N/A	Mandatory	$45	$45	$227	2025 / 2031	2025 / 2031	2025 / 2026
FS Prelim Design - Line Capacity 2027	N/A	Mandatory	$45	$45	$227	2026 / 2032	2026 / 2032	2026 / 2027
FS Prelim Design - Line Capacity 2028	N/A	Mandatory	$45	$45	$227	2027 / 2033	2027 / 2033	2027 / 2028
FS Prelim Design - Line Capacity 2029	N/A	Mandatory	$45	$45	$227	2028 / 2034	2028 / 2034	2028 / 2029
FS Prelim Design - Line Capacity 2030	N/A	Mandatory	$45	$45	$227	2029 / 2035	2029 / 2035	2029 / 2030
	Subtotal		**$21,006**	**$49,306**	**$51,204**			
	Total		**$139,864**	**$208,564**	**$275,861**			