SA Power Networks

Supporting document 5.4

Repex Addendum

2020-25 Revised Regulatory Proposal

10 December 2019

SA Power Networks

SA Power Networks 2020-25 Repex addendum

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1 Introduction

This document has been prepared in response to the AER's draft decision[1] for SA Power Network's (SAPN) regulatory proposal submitted to the Australian Energy Regulatory (**AER**) in January 2019.

1.1 Purpose of document

The purpose of this document is to provide our response to the AER's draft decision on replacement expenditure (**repex)** allowances for the 2020-25 regulatory period. This document explains our revised replacement expenditure proposal, addresses concerns raised by the AER in the draft decision and highlights key changes between our SA Power Networks 2020-25 Regulatory Proposal (**Original Proposal**) and our SA Power Networks 2020-25 Regulatory Revised Proposal (**Revised Proposal**) for replacement expenditure.

1.2 Scope of document

The scope of this document is limited to the areas where there have been material changes in replacement expenditure between our Original Proposal and our Revised Proposal, or where there was specific feedback from the AER that SA Power Networks have addressed as part of the Revised Proposal. It does not include a summary of those projects and programs that have been accepted as prudent and efficient expenditure by the AER in its draft decision or those projects and programs that were not accepted or substituted by the AER and SA Power Networks has accepted the AER draft decision.

[1] AER DRAFT DECISION – *SA Power Networks Distribution Determination 2020 to 2025 – Overview – October 2019* & AER DRAFT DECISION – *SA Power Networks Distribution Determination 2020 to 2025 – Attachment 5 – Capital expenditure* - October 2019

2 Replacement Expenditure

2.1 Our revised replacement expenditure forecast summary

Our revised forecast for replacement capital expenditure for the 2020-25 regulatory period is $682.2 million, $12.7 million higher than our Original Proposal forecast of $669.5 million and it is $23.5 million higher than our forecast expenditure in the current 2015-20 regulatory period.

In our Revised Regulatory Proposal Capex Attachment, we have categorised the replacement expenditure as follows:

Table 1: SA Power Networks' proposal and revised proposal repex forecast compared to the AER's Draft Decision (June 2020, $ million) [2]

	Original Proposal	AER Draft Decision	Revised Proposal	Difference to Draft Decision $
Proposed repex – Option 2	**669.5**	**538.5**	**682.2**	**143.8**
Poles	165.2	120.1	180.7	45.1
Overhead line components	94.7	93.6	109.1	15.6
Switchgear (powerline)	52.0	41.8	54.2	12.4
Service lines	41.7	41.3	49.1	7.8
Other powerline	97.3	95.6	87.2	(6.5)
Zone substation power transformers	26.8	18.7	30.0	11.3
Zone substation circuit breakers	60.5	44.5	58.1	13.6
Zone substation protection relays	16.4	12.9	16.3	3.4
Other substation and CBD	47.2	41.4	43.3	1.9
Telecommunications	30.5	24.0	24.8	0.8
Northfield GIS	11.8	0	11.8	11.8
PILC cables	14.4	4.7	7.1	2.7
North Terrace cable ducts	10.7	0	10.5	10.5

2.2 Long Term Trend

The average age of SA Power Networks' electricity network asset base is ageing rapidly. Over the past two decades, our average asset age has increased from around 25 years old to nearly 45 years old and we currently have the oldest network assets in the National Electricity Market (**NEM**). Amongst Australian distribution network service providers (**DNSP**), SA Power Networks already has a disproportionately large number of very old assets, which is due in part to significant network expansion that occurred during the 1950 to 1970. Although age is not a direct contributor to asset failure, it is highly correlated to many asset failure condition factors, such as corrosion.

Figure 1: SA Power Networks asset investment profile shows SA Power Networks' distribution of electricity network asset installation dates. This shows that across most asset classes, SA Power Networks' installed assets are weighted towards older vintages with relatively few young assets.

[2] This addendum does not seek to address all of the asset classes listed in Table 1. Our Revised Proposal with respect to the following asset classes is discussed in section 5.3 of Attachment 5—Capital Expenditure to our revised proposal: switchgear (powerline); service lines; other powerline; other substation and CBD; telecommunications; PILC cables.

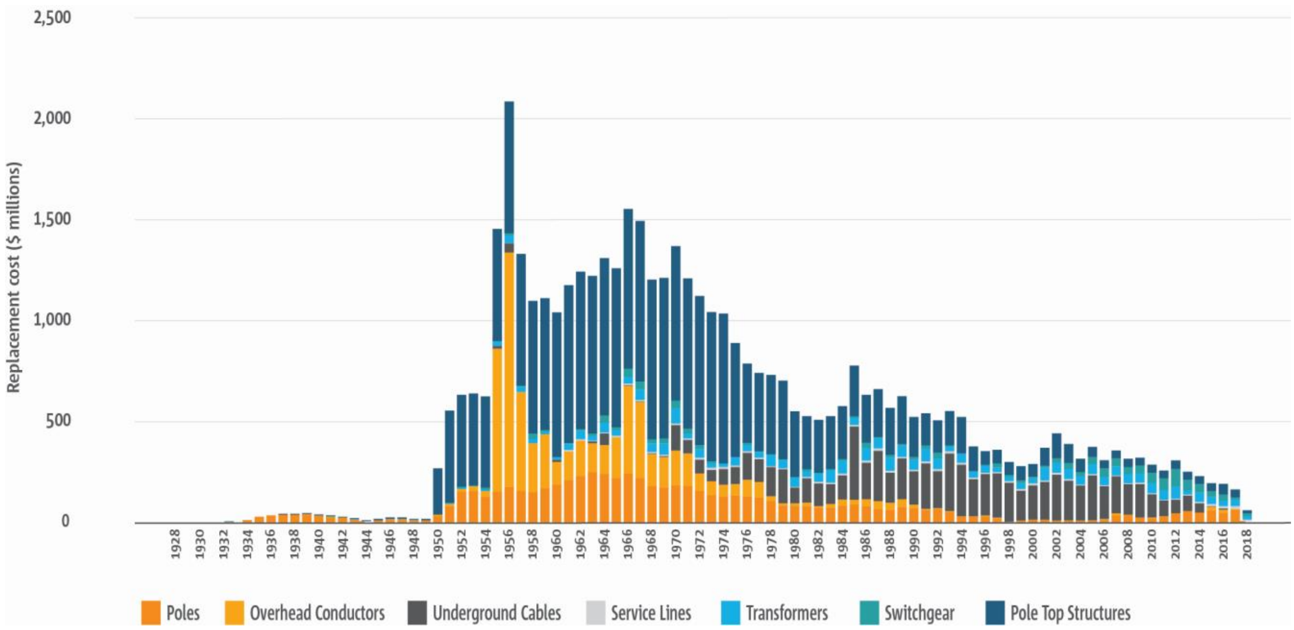


Figure 1: SA Power Networks asset investment profile

The chart below shows the age distribution of poles at seven Australian DNSPs.[3] SA Power Networks carries a much larger proportion of poles from the 1950s and 1960s than other networks. It also shows that not only does SA Power Networks have a large proportion of old assets, but these assets were also built within a very short period of time, creating lumpiness in our age profile. This age profile is not unique only to SA Power Networks' poles, a similar age profile is present in other asset classes, such as overhead conductors, and pole top structures, overhead transformers etc—as these were installed at the same time as the poles were originally installed.

[3] A version of this chart comparing SA Power Networks to all DNSPs in the NEM is contained in the report prepared for us by Frontier Economics. Frontier Economics, *The long-run implications of regulatory repex allowances—Report prepared for SA Power Networks*, 10 December 2019, p.22.

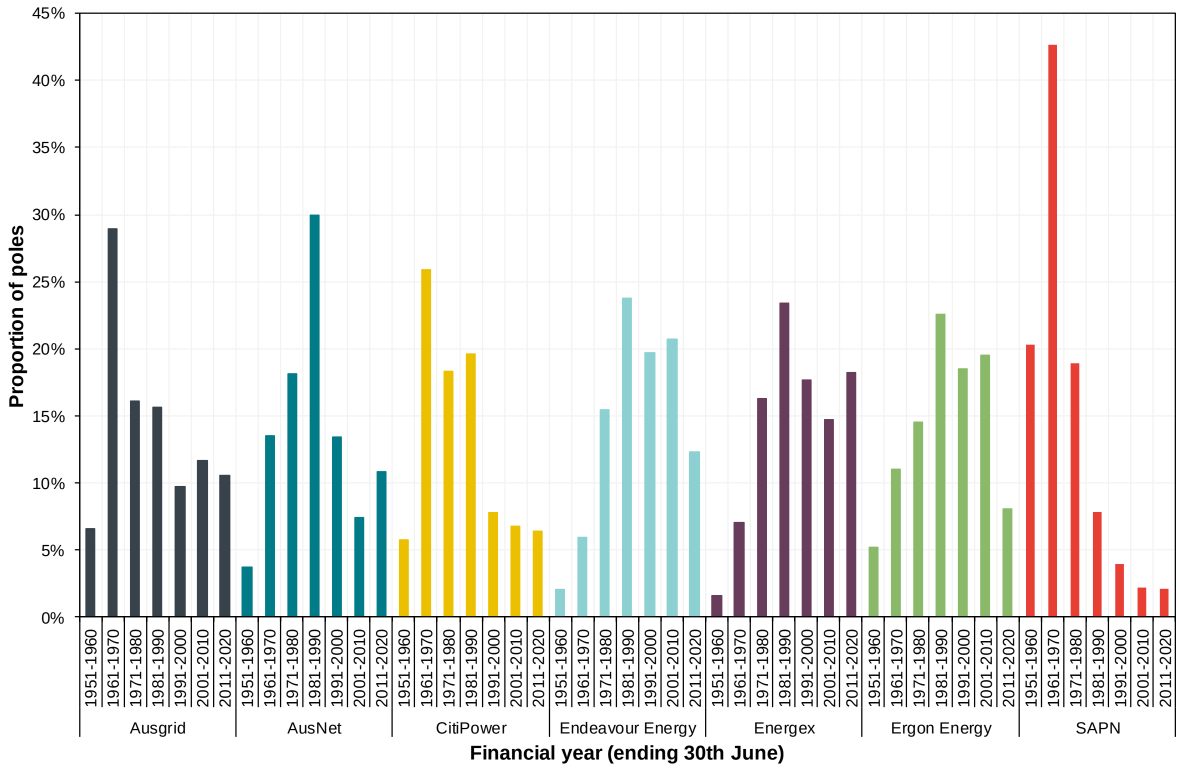


Figure 2: Age profile of pole assets by DNSP

Assets that were installed during the rapid expansion of the 1950's and 1960's have been subject to decades of degradation and are nearing end of life.

While there are short-term fluctuations in replacement expenditure, the long-term expenditure trend indicates an upwards trajectory as the average asset age continues to increase. Over the period 2000 – 2019, SA Power Networks' replacement expenditure has increased from near zero to around $136m per annum to manage the increasing risk exposure of failure across the larger proportion of the asset base.

The current regulatory period's level of replacement expenditure is still low relative to the substantial asset base operated by the network. The current asset replacement rate is below 0.5% of asset replacement value per annum, which is resulting in the mean age of the total asset base increasing by about one year per annum. The current replacement rate is unsustainable over the long run and will need to increase.

An increasing trend for replacement expenditure is supported by forecasts developed using the AER's Repex Model (Figure 3).

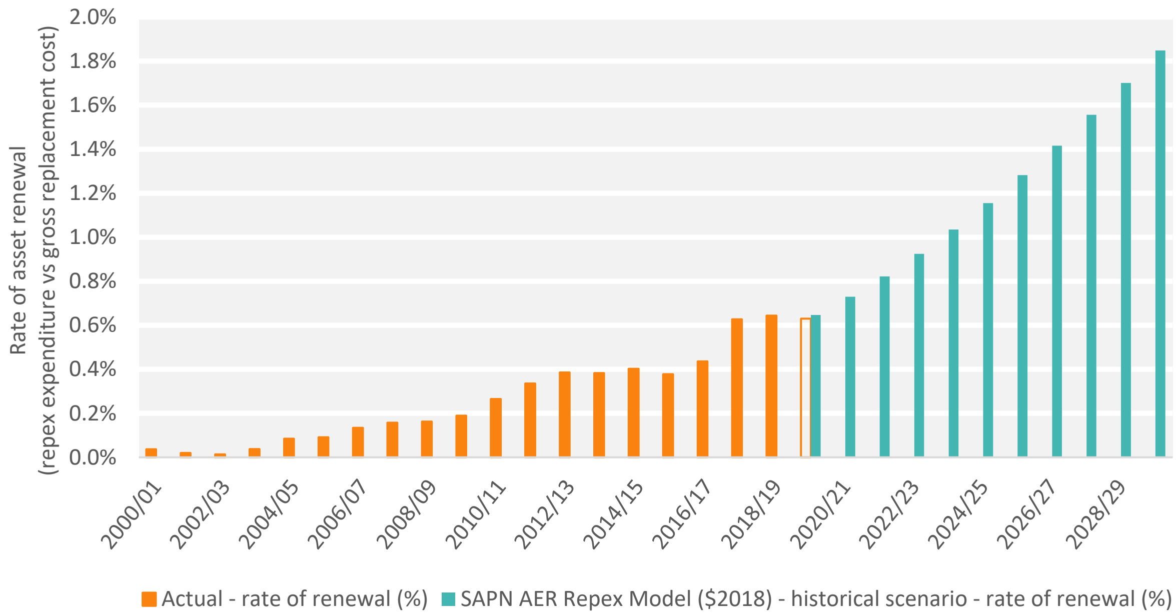


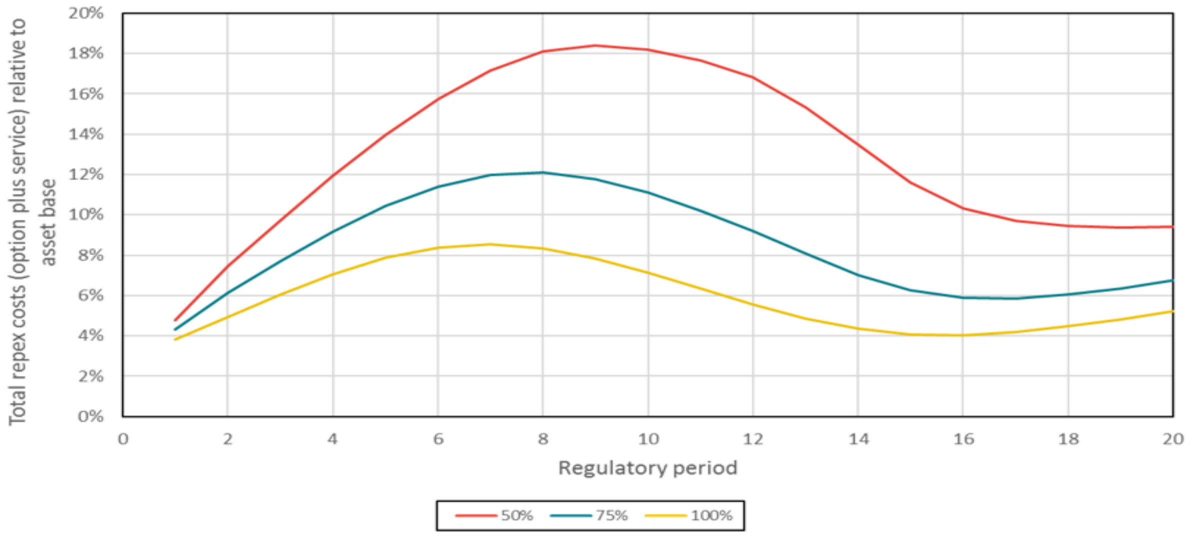
Figure 3: AER Repex Model – Long term repex trend

SA Power Networks has used the AER Repex Model to project the proportion of network assets (by replacement value) that will require replacement over the next 10 years. The AER Repex Model forecasts replacements based on age and observed historical failures and replacements. It also assumes a continuation of current asset and works practices. The results show replacement expenditure requirements increasing by 200% over 10 years.

Independent analysis by Frontier Economics[4] on the long-term implications of replacement expenditure allowances also indicates an increasing requirement for replacement expenditure to address the aging asset base. Figure 4 displays the cost of repex related to SA Power Networks' poles that Frontier's modelling suggests over each 10 year period,[5] relative to the value of the asset base—showing the implications of allowing differing levels of funding to undertake required replacement expenditure (as determined by Frontier's modelling). The yellow line displaying 100% means that all required expenditure is funded and there are no in situ failures. These figures take into account both the cost of undertaking repex (option cost) and the estimated failure premium to reflect additional costs of asset failures in terms of network reliability and safety, including bushfires (service cost). Figure 4 shows the 'bow-wave' as assets age and are replaced, followed by a trough during the period when the old assets have been replaced and the age profile becomes weighted towards younger assets.

[4] Supporting Document – 5.9 - Frontier Economics - The long-run implications of regulatory repex allowances—Report prepared for SA Power Networks.

[5] Each 10-year period is displayed in increments of 2.



Source: Frontier Economics analysis.
Note: Vertical axis represents total repex expenditure (option costs plus service costs – including the safety/reliability cost associated with in situ replacements) relative to the total replacement value of the asset class.

Figure 4: Frontier Economics – long term total costs of repex (option costs plus service costs) relative to asset base: poles

Frontier's analysis shows that SA Power Networks will require higher levels of expenditure, increasing over multiple regulatory periods, as assets reach end of life. In particular, Frontier's analysis identifies that the lumpiness of the investment in SA Power Networks' network assets during the 1950s and 1960s has created a large 'bow wave' of assets that will need to be replaced as they reach the end of their useful lives. This will dictate minimum asset replacement requirements over coming regulatory periods.

Frontier's analysis also draws attention to the intergenerational equity trade-offs for customers arising from decisions to undertake lower than required levels of replacement expenditure via conceptual propositions using data from a sample set of SA Power Networks' asset classes. In summary, Frontier finds that:

- not replacing network assets that are identified as needing replacement will result in more incremental in-situ asset failures, and more assets that need to be replaced in future regulatory control periods, pushing more cost burden onto future generations of customers; and
- replacing assets after they have failed is also more costly for customers than orderly replacement as part of a replacement expenditure program. This is because replacing an asset after it has failed will result in consequences to network safety and reliability for customers.

The issues associated with an old and ageing asset population were also picked up strongly by a number of our customers and stakeholders in our engagement sessions following the AER draft decision. Stakeholders were concerned about deferring required replacement expenditure, or as they put it "kicking the can down the road".

2.3 Replacement Expenditure Strategy

Replacement expenditure comprises investment to replace, modify or extend the life of network assets in response to the ability of the existing assets to safely, reliably and securely perform their function within the network.

The aim of replacement investment is to maintain the safety, reliability, and security of supply performance of the network in a cost efficient and sustainable manner. Replacement decisions are based on addressing key risks associated with asset condition and inherent design issues. An important aspect of the forecasting process is to assess and evaluate the consequences of assets failing in service in terms of the contribution to safety, loss of supply, and security of supply risk.

Included in our replacement investment profile are programs addressing safety, environmental and security compliance obligations that are not necessarily related to historical failure or replacement rates.

2.4 Forecasting Approach

SA Power Networks has prepared two forecast options for replacement expenditure.

- 'Option 1—Base-Case', is the base case forecast of the efficient level of replacement expenditure assuming current asset and works management practices are maintained. That is, assuming we forecast replacement expenditure based on our current network asset management capabilities.

- 'Option 2—Revised Proposal Repex', incorporates reductions in the forecast replacement expenditure due to improved asset and works management practices as a result of the implementation of the Assets and Work (A&W) Stage 2 project.

Based on the cost benefit analysis contained in the Assets and Work Business Case addendum[6], SA Power Networks' proposed replacement expenditure forecast is Option 2.

Both options are presented below.

2.4.1 Option 1: Base Case

The base case option represents the efficient level of replacement expenditure required by SA Power Networks to meet its regulatory and compliance obligations and requirements. The base case assumes no changes are made to our current asset and works practices during the 2020-25 regulatory period.

We have developed the base case replacement expenditure forecast using five modelling approaches. The five approaches were selectively applied based on their appropriateness and the availability of required data.

Condition Based Risk Methodology (CBRM) models were used for assets where detailed asset condition data is available. This approach utilises an industry accepted risk management approach to forecast replacement expenditure. The models forecast changes in risk over time, which is then used to determine the required replacement volumes to maintain the current level of network risk and performance. While a CBRM model was used for the Pole asset class in our proposal (Option 2: revised proposed repex), for the 'Option 1: Base Case repex' forecast Historical Trend modelling was utilised for the Pole asset class.

Historical trend modelling is used to determine asset replacement programs where the detailed data required for CBRM modelling is not yet available or too difficult to obtain. Historical trend uses the expenditure trend over the last 10-year period (2010 to 2020) to forecast the expenditure in the next period. Currently this is the case for a substantial portion of our asset base which is old and ageing with increasing replacement requirements (as detailed in section 2.2). Use of a historical trend in this way instead of a simple average over a 5 year period, will better reflect SA Power Networks' circumstances,[7] including the changing age profile of our network assets—namely, that we have a large cohort of relatively old assets that results in a bow wave of assets moving towards

[6] SAPN revised proposal supporting document 5.31—Assets and Work Program Business Case Addendum, December 2019.
[7] Based on our current asset management capabilities.

the end of their useful lives.[8] Historical trend analysis is therefore an appropriate method for forecasting these replacement expenditure programs.

The use of an increasing trend is supported by the outcomes of the CBRM models that were used for asset classes where detailed condition information is available. These models showed that replacement expenditure requirements are increasing over the 2020-25 regulatory period. The results of the remaining asset classes can reasonably be expected to follow a similar upwards trajectory given the condition deterioration drivers are similar.

We have also reviewed the appropriateness of the fitted trend forecast for major asset classes. In the case of distribution switchgear, the shorter asset life and changes in asset management practices during the current regulatory period resulted in a projected trend that did not provide a reasonable forecast. In place of a trend forecast, SA Power Networks substituted a historical average forecast of replacement expenditure during the current regulatory period for distribution switchgear.

Historical Average is used for replacement expenditure that is expected to be stable over time. For SA Power Networks, this applies to unplanned replacements, which due to their random nature is best forecast using historical averages. We have used the five years of the 2015-20 regulatory period to calculate the historical average. This shorter period was used as it utilises more reliable data (due to data collection and quality improvements made by SA Power Networks) and is representative of current asset management practices. We have also used a historical average for asset replacement programs that are not subject to a bow wave of aged assets (eg. Telecommunications).

Bottom-Up Models are used for short lived assets or assets with a high rate of obsolescence. These models are generally based on recurrent replacement on fixed lifecycles and/or constant replacement rates.

Individual Project NPV Modelling was used for targeted replacement projects that address a specific risk or issue with a unique asset. Replacement expenditure using this approach has been shown to have a positive NPV.

[8] This topic is further explored in the Frontier report. Frontier, *The long-run implications of regulatory repex allowances: report prepared for SA Power Networks*, December 2019.

The application of the modelling approaches by program for Option 1: Base Case are presented in Table 2.

Table 2: Forecasting Approach for Option 1: Base Case

Approach	Asset Classes
Condition Based Risk Methodology (CBRM) Modelling	Transformers (Power Transformers) Switchgear (Substation Circuit Breakers) SCADA & Protection (Substation Protection)
Historical Trend Model	*Planned Replacements:* Poles Pole top structures Conductors Service lines Distribution transformers Cables
Historical Average	*Unplanned replacements:* Poles Pole top structures Conductors Service lines Distribution transformers Cables Other powerline Other substation Telecommunications *Planned Replacements:* Other powerline Other substation Distribution Switchgear Telecommunications
Bottom-up/Other	Telecommunications Other miscellaneous
Individual Project NPV Model	Switchgear (Northfield Gas Insulated Switchgear) Manholes and Ducts (North Terrace cable ducts) Cables (Paper insulated lead covered cables)

'Option 1: Base Case repex' forecasts an efficient level of replacement expenditure over the 2020-25 regulatory period of $740.7m (June $2020).

This forecast is prudently based on our current capabilities and with a view to maintaining service performance and safety, and is efficient on the grounds that it represents the best we can achieve with our current capabilities (including the capabilities achieved via the Assets and Works Stage 1 investments we made over the 2015-20 RCP). The forecast incorporates the benefits from the investments we made in the 2015-20 RCP via the Assets and Works Stage 1 program (i.e. achieved in 2015-20 and expected in the 2020-25 RCP).

2.4.2 Option 2: Revised Proposal Repex

The revised proposal option represents the achievable level of replacement expenditure if SA Power Networks invests in Assets and Work Stage 2 (listed in the Assets and Work Business Case addendum as the recommended option, 'option 1: continue A&W in 2020-25').

The Assets and Work Stage 2 investment will build on the success of Stage 1 enhancing our asset management and work practices. This will enable us to minimise the cost to customers of maintaining network service performance safety, by improving the way we target risk and lowering the cost of replacing assets via bundling efficiencies.

By investing in better systems and automating more of our existing processes, we can also better utilise asset condition data to manage overall network risk more effectively and efficiently. Investing in these improvements now, will allow us to target replacement expenditure to better manage our old and ageing network, lowering costs for customers in the long term. For additional information on Assets and Work Stage 2 see the Assets and Work business case addendum[9].

Consistent with our Original Proposal, the Option 2 revised proposal forecast has been developed by applying the Historical Average forecast rather than the Historical Trend to those asset classes for which we forecast that continued implementation of the Assets and Work program in the 2020-25 RCP will reduce repex levels.

The application of the modelling approaches by program for 'Option 2: Revised Proposal Repex' are presented in Table 3.

Table 3: Forecasting approach for Option 2: Revised Proposal Repex

Approach	Asset Classes
Condition Based Risk Methodology (CBRM) Modelling	Transformers (Power Transformers) Switchgear (Substation Circuit Breakers) SCADA & Protection (Substation Protection) Poles
Historical Trend Model	-
Historical Average	*Planned and Unplanned replacements:* Pole top structures Conductors Service lines Distribution transformers Cables Distribution Switchgear Other powerline Other substation Telecommunications
Bottom-up/Other	Telecommunications Other miscellaneous
Individual Project NPV Model	Switchgear (Northfield Gas Insulated Switchgear) Manholes and Ducts (North Terrace cable ducts) Cables (Paper insulated lead covered cables)

[9] SAPN revised proposal supporting document 5.31—Assets and Work Business Case Addendum, December 2019.

Option 2: Revised Proposal Repex forecasts an efficient level of replacement expenditure over the 2020-25 regulatory period of $682.2m (June $2020), a reduction of $58.5m against the Option 1 Base Case repex forecast.

SA Power Networks' bottom-up modelling of the benefits from the Assets and Work program forecasts a $52.7m (June $2020) reduction in aggregate replacement expenditure requirements. The reduction in expenditure estimated from modelling in the Assets and Work business case addendum closely aligns (though does not fully achieve) the difference between the 'Option 1 Base Case' for repex and 'Option 2 Revised Proposed Repex' forecasts.

In the Original Proposal and our customer stakeholder engagement sessions, SA Power Networks proposed that there would be no change to the replacement expenditure between the 2015-20 and 2020-25 regulatory periods for expenditure forecast using the historical trend approach contingent on continued Asset and Work investment in the 2020-25 period. While the bottom-up modelling of benefits described in the Asset and Work business case do not fully account for the difference between Option 1 and Option 2 in this repex addendum, we have remained consistent with the approach taken in our Original Proposal in developing our Revised Proposal forecast.

Table 4: Efficiency adjustments between Base Case and Revised Proposal options

	$2020
2015-20 Replacement Expenditure	$658.7m
Option 1: Base Case forecast	$740.7m
Option 2: Revised Proposal forecast	$682.2m

The Revised Proposal Repex forecast is dependent on improving our capabilities while ensuring we maintain service performance and safety. This is the most efficient replacement expenditure forecast as it includes efficient investment to improve our capabilities as presented in the Assets and Work Stage 2 business case addendum. This forecast represents the best that can be achieved, contingent on improving our practices via Assets and Work Stage 2 and is shown in Figure 5.

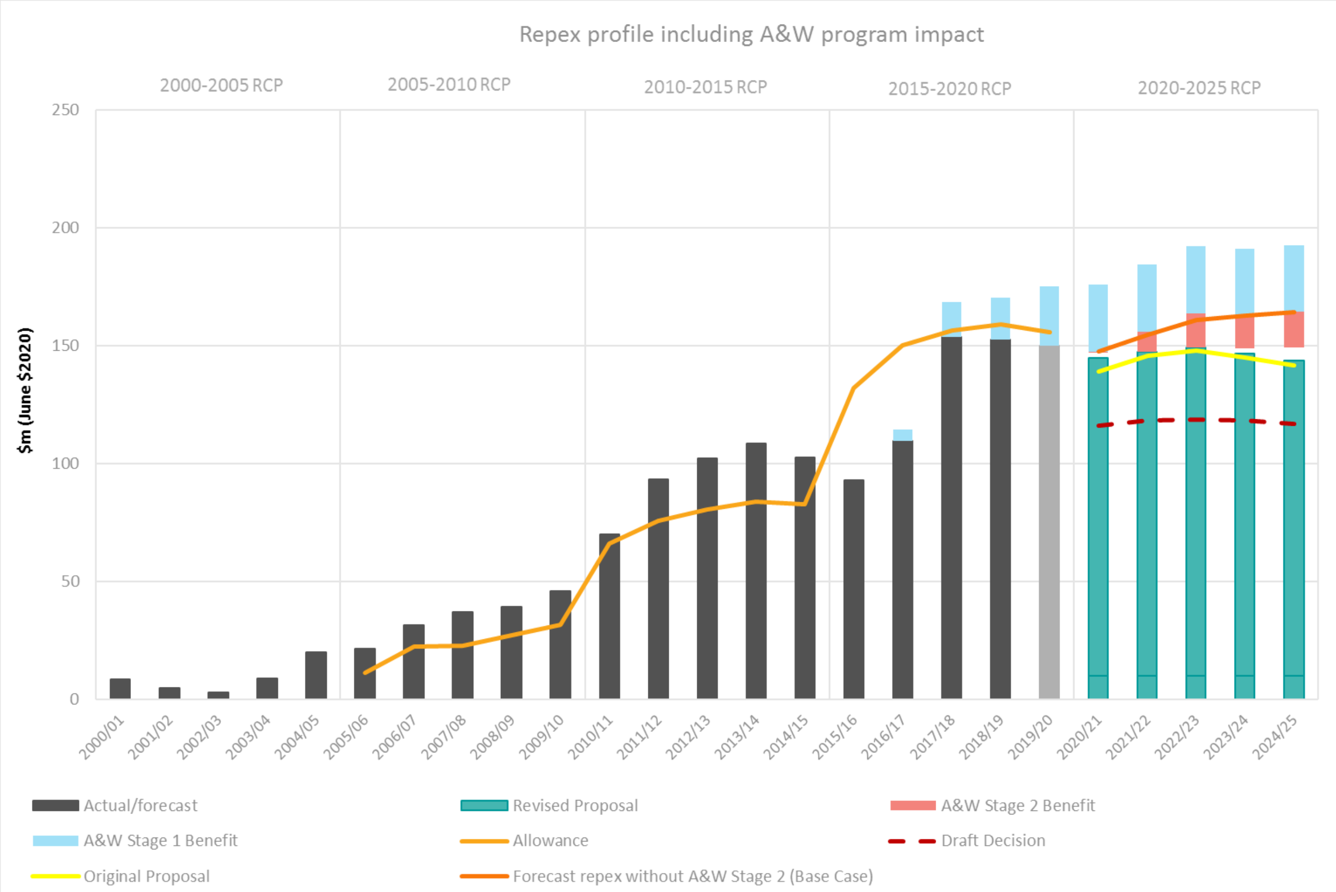


Figure 5: Historic and forecast replacement expenditure showing Assets and Works Stage 1 benefits during the 2021 – 2025 regulatory period (includes Cable and Conductor expenditure reclassified as Opex in the 2020-25 period to make comparable with pre 2020 Repex

2.5 Stakeholder Engagement

We have undertaken a comprehensive stakeholder engagement program for our 2020-2025 Regulatory Proposal involving over 5,000 participants across more than 100 workshops and other activities since the program commenced in February 2017. Stakeholders have been supportive of investment in better use of data to improve the productivity of the replacement expenditure program.

Stakeholder submissions to the AER on our Proposal reinforced the need for SA Power Networks to invest in productivity enhancing systems included:

> *"The secret of SA Power Networks' success has been best practice asset management which has kept assets in service longer than their technical life… this has been enabled by well implemented IT changes which allow for data analysis."*[10]
>
> *"Identify the [ICT] costs as part of the capital works but include a strong and identifiable 'downward step' in operating costs and capital requirements that flow from the ICT investment."*[11]

We have engaged further with our customers and stakeholders on replacement expenditure and Assets and Work since the AER Draft Decision, including hosting a workshop on 25 October 2019 with our Customer Consultative Panel, Reference Group members, the AER's Consumer Challenge Panel 14 (CCP14), jurisdictional government and AER representatives.

- [10] *Dynamic Analysis Pty Ltd, Technical regulatory advice to ECA*, 16 May 2019, p.16
- [11] *CCP14, Advice to the AER on the SA Power Networks 2020-25 Regulatory Proposal*, 16 May 2019, p.47

In this workshop, we actively engaged with our customers and stakeholders by seeking their preferences with respect to the trade-offs for customers within our considered options for replacement expenditure and the Assets and Work program. We outlined three possible scenarios with respect to our Revised Proposal to the AER.

1. **Scenario 1: SA Power Networks accepts the AER Draft Decision**—ie lower forecast repex than proposed, and no further Assets and Work investment in 2020-25. We outlined our reasons for why the AER's Draft Decision allows insufficient expenditure for us to maintain service performance and safety.
2. **Scenario 2: SA Power Networks to propose higher repex and no A&W investment**—ie the 'Option 1: base-case' repex forecast and 'base-case: do nothing (no further investment)' for the A&W program. This was shown to have a lower short-term price impact on customers, but higher long-term costs than Scenario 3.
3. **Scenario 3: SA Power Networks to propose lower repex and propose the A&W IT investment**—ie the 'Option 2: Revised Proposal Repex' and 'Option 1: A&W Stage 2' business case. This was shown to have a higher short-term price impact on customers, but lower long-term costs than scenario 2. This is because IT investments have shorter asset lives than network assets, meaning the costs of these investments are recovered over a shorter period of time.

There was general consensus and support from customers and stakeholders for Scenario 3 which forms the basis of our Revised Proposal ('option 2: Revised Proposal repex'). Customers and stakeholders told us that:

- SA Power Networks should in the 2020-25 RCP continue investment in improving the efficiency of network management and asset replacement / refurbishment work. It would be unacceptable to stakeholders for SA Power Networks to not look at the things that the A&W program seeks to do in light of the significant looming uplift that will be required in replacement expenditure.[12]
- Stakeholders preferred Scenario 3, in appreciation of the need to minimise inter-generational equity issues and avoiding 'kicking the can down the road' in their words.
- While suggesting Scenario 3 should be presented to the AER in SA Power Networks' Revised Proposal, our customers and stakeholders encouraged the AER to fully assess the modelling that SA Power Networks has undertaken as this was beyond their areas of expertise.[13]

These sentiments were echoed in subsequent meetings with the SAPN CCP and other reference group members, and we have committed to ongoing engagement with our stakeholders on this important topic.

3 How we are responding to the AER's feedback

In its draft decision, the AER determined that SA Power Networks had not demonstrated that our forecast replacement expenditure of $669.5 million was prudent and efficient. The AER determined a substitute estimate of $538.5 million, which is $131.0 million lower than SA Power Networks' forecast.

The AER's decision has been driven by the following observations:

[12] V*erbal comment by a stakeholder during the workshop*, 25 October 2019.

[13] For example, a stakeholder comment in our evaluation form stated: "*this is a reasonable option, provide your reasons and what Id hope is that the AER continue to apply the same rigour to your proposal and consider feedback provided in stakeholder submissions*."

1. Risk has been overstated in SA Power Networks' condition-based modelling and therefore forecast repex required to mitigate this risk;
2. Insufficient evidence to support the inclusion of the last two years of the current period (2018–19 and 2019–20), where the historical trend is used to derive forecast repex; and
3. SA Power Networks has not demonstrated that its repex forecast would need to increase as a result of removal of the A&W program.

3.1 Modelled risk has been overstated

What the AER determined:

The AER provided commentary on the Condition Based Risk Methodology (CBRM) approach used for forecasting replacement expenditure for several asset classes. The draft decision raised concern with our assumptions, inputs and how the outputs of the methodology were used to inform the forecast for the following reasons:

- The CBRM model forecasting methodology applied by SA Power Networks maintains risk at 2018 or 2019 levels, but it has not been demonstrated why the 2018 or 2019 risk levels are reasonable or why a higher or lower level of risk is not acceptable;
- The CBRM models calculate the annual deterioration of an asset population as measured at the end of regulatory period (2025), while assuming that there is no intervention during the period, which overstates risk;
- The risk consequence values are more closely aligned with a maximum severity consequence, rather than average consequence, which overstates modelled risk;
- As the CBRM models overstate risk, they must also overstate the expenditure required to reduce risk; and
- The replacement expenditure forecast developed using the CBRM models was not validated using other forecasting approaches.

The AER determined that SA Power Networks condition-based modelling overstates risk and therefore the forecast repex required to mitigate this risk.

Our response and what we have changed:

The AER’s concerns with our repex forecast were principally focused on characteristics of the CBRM methodology we used to forecast poles, circuit breakers, protection relays and power transformers. The AER also had concerns that our governance process did not adequately test the prudency and efficiency of our proposed capex.

We have taken into consideration the AER’s feedback and would like to clarify the following:

- The CBRM methodology employed is a widely accepted, non-proprietary, mature methodology. It is mandated for us in the UK and has been used by many DNSPs in Australia.

- SA Power Networks implementation of CBRM has been developed specifically to ensure it is open and transparent. All inputs, outputs and algorithms can be viewed and tested. It is not a “black box”. It is also tightly integrated with our Asset Management System (corporate IT systems) to facilitate operational decision making (c.f. regulatory forecasting) and to enable integration of our full set of actual data. The downside of this is that it is difficult to “put into a spreadsheet” to facilitate isolated examination.

- SA Power Networks is obligated to maintain risk and service levels over time.[14] This obligation comes from the expenditure objectives in the National Electricity Rules[15] as well as jurisdictional regulations and our distribution licence conditions:[16]

  - SA Power SA Power Networks is required by the *Electricity Act 1996* (SA) to hold a licence to operate its distribution network.[17] As a condition of that licence,[18] SA Power Networks must prepare, maintain and comply with a safety, reliability, maintenance and technical management plan (**SRMTMP**) in accordance with the requirements of the *Electricity (General) Regulations 2012* (SA). The Regulations require the SRMTMP to, amongst other things, deal with the management of a range of risks including the reduction of the risk of death or injury, or damage to property, arising out of the operation of the network, identifying infrastructure that is at risk of failing/malfunctioning, and identifying risks posed by aerial lines.[19] SA Power Networks is also required by the Regulations to provide annual reports to the Technical Regulator setting out, amongst other things, the extent of SA Power Networks' compliance, or failure to comply, with the risk minimisation and management obligations under the SRMTMP.[20]

  - Current service levels are also included in the various incentive schemes' service level targets that SA Power Networks is penalised for not meeting. We are also required, as a condition of our distribution licence, to meet service standard levels contained in the South Australian Electricity Distribution Code. These include service standard framework targets for reliability of supply, customer service and Guaranteed Service Levels. The Essential Services Commission of South Australia (**ESCoSA**) is the jurisdictional body that establishes these standards.

- The CBRM modelling methodology used by SA Power Networks whereby risk and replacement expenditure are only calculated at the end of the regulatory period does not overstate expenditure requirements. SA Power Networks has provided additional analysis to the AER that compares the end of period approach to an annual approach and shown that there is a negligible difference. SA Power Networks understands that the AER's concern stemmed from a misinterpretation of the relationship between risk and forecast replacement expenditure that was clarified during the CBRM modelling workshop with the AER on November 15th.

- The risk consequences that are quantified in the CBRM models use average consequence values for the definition of the risk being used. For example, the definition of bushfire is a catastrophic bushfire and therefore the average consequence is very high. Where the consequence value aligns with the most severe outcome (such as a catastrophic bushfire), the probability of the risk happening is also representative of the severity level. SA Power Networks does not model every minor fire start (such as a small supressed grass fire) as being valued as a catastrophic bushfire. This is further addressed in the independent verification report on the consequence values used in the CBRM modelling.

- [14] While we have significantly increased our repex over the past 20 years, our overall long-term performance trend in managing safety and reliability must be considered steady at best. '*Supporting Document 5.4.1: managing SA Power Networks' ageing assets*', contains a series of charts displaying the performance of our network since 2005/06 in relation to several indicators: number of high voltage outages—increasing; outages from equipment failure—steady; shocks from our infrastructure—increasing; fire starts—increasing; pole failures—increasing; pole top failures—steady; conductor failures—steady; reliability performance—underlying duration performance is steady but the customer experience is deteriorating.
- [15] NER, clause 6.5.6(a).
- [16] Our distribution licence conditions and the expenditure objectives in the NER, require us to maintain service performance and safety. Our expenditure forecasts are developed using a risk metric that aims to maintain both service performance and safety.
- [17] *Electricity Act 1996* (SA), section 15.
- [18] Condition 8.1 of our distribution licence.
- [19] *Electricity (General) Regulations 2012* (SA), regulation 72(2).
- [20] Ibid, regulation 73(3).

- Additionally, SA Power Networks has not included low severity consequences in the CBRM models. Whilst low consequence outcomes are more common, due to their low value, they do not significantly increase total risk. The total risk modelled by the CBRM models is understated as the inclusion of low severity risk consequences would increase the total risk; and

- The replacement expenditure forecast produced by the CBRM models have been assessed against the outcomes of the AER Repex Model and historical average and historical trend analysis.

We have responded to the AER concerns as follows:

- We have had our CBRM inputs independently verified[21];
- We have implemented most recommendations from the CBRM independent verification, including changes to values used for risk consequences and the likelihood of consequences occurring following an asset failure, and updated our CBRM results and replacement expenditure forecast;
- We reviewed our modelled risks against actual risk incurred data where available and adjusted our assumptions to align to actual risk;
- We have held workshops with the AER to walk through the model; and
- In order to make the model more accessible and transparent, we have developed a set of excel spreadsheets which replicate not only the interventions (provided previously) but now provide all modelling steps after the Health Index calculation (this step is still reliant on connection to our corporate systems).

Key changes that SA Power Networks has made to the CBRM modelling in response to the recommendations by the independent verifier include:

- Safety Risks have been updated to align with the Value of Statistical Life (VSL) estimates published by the Australian Government;
- Industry aligned disproportionality factors have been applied to safety risks;
- Fire risk outputs have been aligned with the fire risk modelling undertaken for our Bushfire Mitigation strategy;
- An issue where fire risk was rounded to zero in the poles CBRM model has been addressed;
- Environmental risk consequence values have been updated to use industry standard values; and
- Environmental (oil) consequence probabilities have been revised for transformers to better reflect the presence of bunding and to align with observed risks incurred in recent years.

After these changes were applied, SA Power Networks compared 2018/19 actual consequences against the CBRM modelled 2018/19 risk values. The analysis showed that all modelled risks are now comparable with observed risk, noting that some risks (e.g. catastrophic bushfires) are infrequent and therefore underrepresented in the observed risk values (refer Appendix B).

In our Revised Proposal, we have provided updated replacement expenditure forecasts that are based on the updated model input parameters discussed above based on the recommendations in the independent report.

- [21] SAPN revised proposal supporting document 5.5: CutlerMerz, CBRM Model value of consequence independent report.

3.2 Insufficient evidence for the selection of historical base years for trend analysis

What the AER determined

The AER provided commentary that, in general, there was insufficient evidence to support the inclusion of the forecast replacement expenditure for the last two years of the current period (2018–19 and 2019–20) to forecast replacement expenditure using the historical average method.

The AER also commented on the significant increase in replacement expenditure in 2020-25, when compared to SA Power Networks' long-term average when excluding the last two years of the current regulatory period. The draft decision rejected our proposed forecast for the following reasons:

- The estimated replacement expenditure for the last two years of the current regulatory period represent a significant step up on the previous five years of actual expenditure (approximately 62.0 per cent higher than the average of 2013–18 regulatory years) as well as the previous 10 years; and
- These high estimates inflate the forecast for the 2020-25 period where the historical average method has been used.

Where the AER provided a substitute replacement expenditure allowance for an asset class, the average of the most recent five years actual replacement expenditure was used.

Our response and what we have changed:

We have taken into consideration the AER's feedback and would like to clarify the following:

- The first two years of the 2015-20 regulatory control period were abnormal and reflected anomalous conditions which affected our actual replacement expenditure levels:
    - The 2015/16 regulatory year was materially impacted by the financing uncertainties arising from the AER at the time first making a Preliminary Determination in April 2015 for the 2015-20 period. This decision provided for an unexpected, materially lower ($300 million plus) revenue allowance than anticipated, which Preliminary Determination was then revoked and substituted by the AER's Final Determination.[22]
    - Accordingly, when SA Power Networks prepared its 2016 calendar year budget in mid 2015 it only had the Preliminary Determination to guide its 2016 budget setting process. Budgets were set lower in 2016 reflecting this uncertainty. The Final Decision was not published until October 2015, after the 2016 budget had been approved by SA Power Networks' Board.
    - In addition, capital expenditure in the 2016/17 regulatory year was materially impacted by unprecedented weather, the worst storm year on record in South Australia. A record number of nine major event days occurred in this regulatory year, leading to resources being diverted from the asset replacement program to emergency response and repairs operating activities.
    - Also, over the first two years of the period we delayed some replacement expenditure as we transitioned to our 'value-based replacement' approach using our Valuing and Visibility Tool;
- Historical average expenditure was used for forecasting with the assumption that the Assets and Work Stage 2 program would proceed. SA Power Networks' underlying assumptions were that, absent of Assets and Work Stage 2, replacement expenditure would trend upwards during the 2020-25 regulatory period;

- [22] This was because transitional rule 11.60.4 of the National Electricity Rules was in effect, which provided for: (1) the AER to make a Preliminary Determination for SAPN for the 2015-20 RCP in April 2015 to cover the period 1 July 2015 to 30 June 2016; and (2) the AER to revoke that Preliminary Determination in October 2015 and substitute it with a Final Determination to take effect from the date of revocation and apply for the remainder of the 2015-20 RCP.

- The actual expenditure for the 2018/19 year is now available and should be used in place of the 2012/13 year for historical average comparisons;
- The actual expenditure for 2018/19 was close to the estimated expenditure and, therefore, the estimate was not inflated nor unreasonable. The estimate has now been shown to have reflected the actual circumstances of the network; and
- We have updated our 2019/20 forecast since our Original Proposal.

Due to the feedback on the incorporation of the Assets and Work Stage 2 program on forecast replacement expenditure, in our Revised Proposal we have reviewed our approach to forecasting replacement expenditure and:

- Updated 2018/19 estimate used in calculations with 2018/19 actual;
- Updated 2019/20 estimate used in calculations with the updated 2019/20 estimate, based on latest information including our actuals for 2018/19.;
- Provided information to clarify the lower expenditure during the first three years of the current regulatory period;
- Used historical trend over 10 years, including estimated 2019/20, to produce a 'option 1: base case repex forecast' (see Section 2.4). Historical trend produces a more accurate forecast of the base case replacement requirements of SA Power Networks' old and ageing network assets than historical average does (refer Section 2.2); and
- Continued to use historical average during the current regulatory period (including 2019/20) to determine the expenditure forecast for the proposed expenditure option (Option 2).

Use of a historical average based on the five most recent years of actual expenditure is inappropriate given the increasing age of our network assets and the increasing repex profile this will drive. The historical average (where used) in our Original Proposal was to account for the continued investment in the Assets and Work program. 'Option 2: revised proposed repex' (the preferred option) was developed using an approach consistent with our stakeholder engagement and our Original Proposal on the basis that continued investment in the Assets and Work program would allow us to achieve an expenditure in line with the current period (refer Section 2.4.2).

3.3 Deferral impact of A&W not reflected in repex modelling/forecast

What the AER determined

The AER provided commentary regarding SA Power Networks position that its repex forecast "will need to be increased by $65 million ($2017) if the Assets and Work Stage 2 Program (ICT expenditure) for the 2020–25 RCP is not allowed by the AER. The AER determined that SA Power Networks had not demonstrated why its repex forecast would need to increase as a result of removal of the proposed Assets and Work program. The draft decision rejected the proposed forecast for the following reasons:

- No evidence was provided to demonstrate the relationship between the Assets and Work Stage 2 investment and deferral of replacement expenditure in SA Power Networks' replacement expenditure forecast;
- Apparent inconsistency between the forecasting methodologies did not support SA Power Networks' claim that it has incorporated replacement expenditure deferral in its repex forecast; and
- No evidence was provided to demonstrate the method for estimating replacement expenditure deferral due to Assets and Work Stage 2.

The AER determined SA Power Networks had not demonstrated how the benefits of the Assets and Work investment is incorporated into the replacement expenditure forecast. As a result, and because the original business case did not demonstrate the economic value of the A&W Stage 2 program benefits, the AER did not approve expenditure for the Assets and Work Stage 2 program.

Our response and what we have changed

The AER's concerns with SA Power Networks' replacement expenditure forecast were principally focused on the apparent inconsistency in methodologies used to estimate deferral of replacement expenditure. The AER also had concerns that our methods for estimating replacement expenditure deferral were inadequate.

We have responded to the AER's concerns by:

- Refining our modelling to calculate the reduction in replacement expenditure achievable from the Assets and Work Stage 2 project (refer Section 2 of this addendum);
- Updating our Assets and Work business case[23] to demonstrate the positive NPV that this project will deliver;
- Clearly linking replacement expenditure deferral benefits included in the Assets and Work business case to our revised replacement expenditure allowance (refer Section 2.4); and
- Highlighting the stakeholder expectations of SA Power Networks with regard to continuous improvement of our asset management practices that were identified through our extensive stakeholder engagement program. That is, that our Revised Proposal on replacement expenditure and to invest in Assets and Work Stage 2 over the 2020-25 RCP is consistent with the preferences of our customers and stakeholders having considered the short and long-term trade-offs for customers.

3.4 Consideration of broader factors

In its Draft Determination, we also consider that the AER has given inadequate consideration to broader and 'top-down' factors which may provide guidance as to the reasonableness of SA Power Networks' replacement expenditure forecasts, that is, whether these forecasts will be sufficient to:

- to recover our efficient costs consistent with the Revenue and Pricing Principles in the National Electricity Law; and
- to maintain service performance and safety and comply with our distribution licence conditions, consistent with the expenditure criteria in the National Electricity Rules.[24]

In deciding if our Revised Proposal forecast replacement expenditures comply with the expenditure criteria in the NER by being prudent, efficient and based on realistic expectations, the NER require the AER to have regard to several and specifically listed factors and sources of information (i.e. the NER expenditure factors)[25], in addition to any other information considered to be relevant. We consider that the AER should have regard to the following:

  - Our consistent relative efficiency compared to other DNSPs, as evidenced in the AER's annual benchmarking reports, showing that we have been relatively efficient with respect to the investments we have made in our network and the operation and maintenance of our network.[26]

[23] SAPN revised proposal supporting document 5.31—Assets and Work Business Case Addendum, December 2019.
[24] Sections 6.5.6(a) and 6.5.7(a) of the NER.
[25] Sections 6.5.6(e) and 6.5.7(e) of the NER.
[26] For example, SA Power Networks benchmarks as the most efficient distribution network on a state-wide basis in relation to Multilateral Total Factor Productivity, and is within the top four most efficient distribution networks on an opex multilateral partial factor productivity basis and on the basis of the AER's four econometric models. AER, *Annual Benchmarking Report—Electricity Distribution Network Service Providers*, November 2019.

- Our having the lowest RAB growth[27] of any DNSP in the National Electricity Market (NEM) showing that we have not overinvested in our network such that there is a lessened need to replace network assets.[28]
- The age profile of SA Power Networks' assets, with relatively old assets by any measure which were predominantly built within a short period of time.[29] This is a key issue for our network and is therefore a crucial factor in deriving forecast expenditure that is reflective of SA Power Networks' circumstances—the expenditure objectives in the NER require that our forecast expenditures be reflective of our circumstances. 'Supporting Document 5.9' provides an independent report prepared by Frontier Economics which elaborates further on the need to consider SA Power Networks' unique circumstances, and indeed the unique circumstances of any DNSP with respect to their network age profile in forecasting replacement expenditure requirements.
- Other factors specific to the circumstances of SA Power Networks. Section 5 of 'Supporting Document 5.9' provides observations as to the approach that other regulators have taken to this issue, in this case, OFGEM.
- Anticipated trends in the network age profile and implications for asset condition and performance;
- Outputs from as wide a range of models as possible that may be utilised to forecast future repex. To this end we also refer to Appendix C to this Repex Addendum, which recommends changes that the AER could feasibly make to improve the quality of outputs from the AER's Repex Model.
- The implications and risks associated with providing inadequate repex allowances.
- The concerns of our electricity consumers as expressed to SA Power Networks in the course of our engagement with consumers. As outlined in section 2.5 of this Repex Addendum, our customers have clearly indicated that they wish to minimise intergenerational equity issues arising from under-funding replacement expenditures and in their words, "kicking the can down the road" to future generations of consumers.

4 Specific Projects and Programs

In its Draft Decision the AER identified some specific projects and programs that need to be addressed in our Revised Proposal. These projects and programs are discussed below and have been itemised to align with the AER Draft Decision.

4.1 Poles

What the AER determined

The AER provided commentary on the approach used for determining forecasts for pole replacements. The draft decision rejected our proposed forecast for the following reasons:

- Overstated risk and general issues with CBRM as described above;
- Forecasts for the Line Clearance program was not developed using CBRM, yet SA Power Networks claimed all Poles expenditure were developed using CBRM;
- Pole failure rates are stable excluding significant events;
- No sensitivity analysis was provided to address any bias of inputs in CBRM models; and
- No evidence to demonstrate increase in defects represents an increase in network risk.

- [27] ACCC, Restoring electricity affordability and Australia's competitive advantage, June 2019, p.ix
- [28] SA Power Networks also has a significantly lower RAB per customer than the average across NEM DNSPs, based on data from the AER's published performance data for DNSPs.
- [29] This subject is analysed in an independent report prepared for SA Power Networks by Frontier Economics, provided in our Revised Proposal as Supporting Document 5.9—Frontier Economics: the long run implications of regulatory repex allowances.

The AER determined that SA Power Networks had not demonstrated a need to increase its poles replacement expenditure in the 2020–25 period over and beyond its actual current levels. The AER substitute estimate is based on 2013-18 historical average.

Our response and what we have done

SA Power Networks have statutory obligations to ensure our overhead powerlines meet clearances outlined in the (SA) Electricity (General) Regulations 2012. Line clearance expenditure is related to the rectification of line clearance breaches identified through our existing inspection practices.

The forecast expenditure for line clearance in our regulatory proposal was developed using historical actual expenditure not using CBRM models. However, expenditure in the line clearance rectification category largely relates to the replacement of poles, and we therefore account for this volume of pole replacements in our Poles CBRM model. To ensure we do not understate the risk reduction achieved through non-condition pole replacements we include these replacements in the CBRM model.

This is the same approach taken for the replacement of poles damaged by third parties (e.g. cars damaging poles). The poles replaced due to third party damage or line clearance breaches are treated as 'random' replacements in the CBRM model – removing an amount of risk from the network by replacing an aged pole with a new pole. Our CBRM pole model forecast expenditure would be higher had we not included these replacements.

We have revised our investment proposal, taking into consideration the AER's feedback. Our further work includes the following:

- We have had our CBRM inputs independently verified[30];
- We have implemented most recommendations from the CBRM independent verification, including changes to values used for risk consequences and the likelihood of consequences occurring following an asset failure, and updated our CBRM results and replacement expenditure forecast (see Section 3.1);
- We reviewed our modelled risks against actual risk incurred where data is available and adjusted our assumptions to align to actual risk;
- We have now included fire risks in the Poles CBRM model, while revising the assumptions for bushfire risk consequence and likelihood;
- Pole failure data has been updated in our asset management documents which reflect the upward trend;
- We have undertaken a review of inputs to the CBRM model namely, the probability and consequence values and cross-checked that they reflect known historical values; and
- We have revisited our CBRM model to ensure the risk reduction due to pole replacements in other expenditure categories (eg. augex and customer connection) are accounted for along with poles replaced due to third party damage or as part of the line clearance program.

[30] SAPN revised proposal supporting document 5.5: *CutlerMerz, CBRM Model value of consequence independent report*.

Our revised forecast

SA Power Networks revised forecast for the poles programs is $180.7 million, $60.6million higher than the AER substitute forecast of $120.1 million as detailed in Table 5 below.

Table 5: RRP Forecast Expenditure ($2020, incl. overheads and escalators)

	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Pole replacement	25.2	25.4	25.6	25.7	25.9	**127.8**
Pole refurbishment	7.4	7.4	7.5	7.5	7.5	**37.3**
Line clearance rectification	3.1	3.1	3.1	3.1	3.1	**15.5**
Total	**35.7**	**36.0**	**36.1**	**36.4**	**36.5**	**180.7**

4.2 Pole top structures

What the AER determined

The AER provided commentary on the approach used for determining forecasts for pole top structure replacements. The draft decision rejected our proposed forecast for the following reasons:

- The forecast is based on a continued flat investment profile from the 2015–20 RCP, which includes the high estimates in the last two years of the current RCP; and
- That the high estimates in repex corresponds to an increase in inspections that are identifying more defects is unreasonable because SA Power Networks have not demonstrated:
  - Increasing defects reflects increasing risk.
  - A decline in network performance associated with increasing defects.

The AER determined that SA Power Networks had not demonstrated a need to increase its pole top structure replacement expenditure in the 2020–25 period over and beyond its actual current levels. The AER substitute estimate is based on the historical expenditure for pole top structures across the 2013-18 period.

Our response and what we have done

We largely accept the AER's Draft Decision methodology and have revised our forecast to include 2018/19 actual expenditure and our latest forecast expenditure for 2019/20.

We have exceeded forecast expenditure in 2018/19 on the basis that our Value and Visibility tool had assessed that the highest risk, lowest cost work required prioritising expenditure for Pole Top Structures thereby increasing category expenditure and optimising remaining expenditure across our asset classes. We have revised our forecast to reflect this.

Our revised forecast

SA Power Networks revised forecast for the pole top structure program is $144.2 million as detailed in Table 6 below.

Table 6: Revised Proposal Forecast Expenditure ($2020, incl. overheads and escalators)

Pole top structures	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Overhead line components	21.6	21.7	21.8	21.9	22.1	**109.1**
Overhead switchgear	6.9	7.0	7.0	7.1	7.1	**35.1**
Total	**28.5**	**28.7**	**28.8**	**29.0**	**29.2**	**144.2**

4.3 SCADA and Protection – Zone Substation Protection Relays

What the AER determined

The AER provided commentary on the approach used for determining forecasts for protection relay replacements, data networks and network telecommunications planning labour capitalisation. The draft decision rejected our proposed forecast for the following reasons:

- The substation protection relays forecast was based on the SA Power Networks' Protection CBRM model. The AER determined that the CBRM models overstate risk and have regard to general issues with SA Power Networks' CBRM as described above in Section 3.1;
- The data networks project was not supported by appropriate analysis e.g. failure rate or cost-benefits; and
- Actuals associated with the labour for project management, engineering and/or design of a network telecommunications solution was 47 per cent lower than the forecast. No justification was provided for what is driving the increase in these costs.

The AER determined that SA Power Networks had not demonstrated a need to increase its SCADA and Protection replacement expenditure in the 2020–25 period over and beyond its actual current levels. The AER substitute estimate is based on the historical expenditure for SCADA and Protection across the 2013-18 period.

Our response and what we have done

We largely accept the AERs determination on our data networks project and network telecommunications planning labour capitalisation. SA Power Networks acknowledges customer price pressures and agrees not to pursue this in our Revised Regulatory Proposal.

With regard to Protection Relays, we have updated our CBRM model and had our inputs independently verified. We have also revised our investment proposal taking into consideration the AER's feedback.

Our further work includes the following:

- We have had our CBRM inputs independently verified[31];
- We have implemented most recommendations from the CBRM independent verification, including changes to values used for risk consequences and the likelihood of consequences occurring following an asset failure, and updated our CBRM results and replacement expenditure forecast (see Section 3.1);
- We reviewed our modelled risks against actual risk incurred where data is available and adjusted our assumptions to align to actual risk;
- Failure data has been updated in our asset management documents to reflect the current trends.

Our revised forecast

SA Power Networks revised forecast for the SCADA and Protection program is $16.3 million, $3.4 million higher than the AER substitute forecast of $12.9 million as detailed in Table 7 below.

Table 7: RRP Forecast Expenditure ($2020, incl. overheads and escalators)

	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Zone Substation Protection Relays	3.4	3.4	3.3	3.1	3.2	**16.3**

[31] SAPN revised proposal supporting document 5.5: CutlerMerz, CBRM Model value of consequence independent report.

4.4 CBD ducts and manholes – North Terrace

What the AER determined

The AER provided commentary on the approach used for determining forecasts for CBD ducts and manholes replacement expenditure. The draft decision rejected our proposed forecast for the following reasons:

- The AER specifically assessed the North Terrace duct replacement program;
- The North Terrace duct replacement program had already been approved in the 2015-20 period, yet SA Power Networks deferred the program in its entirety;
- SA Power Networks state the whole program is reliability driven yet has not provided any cost-benefit analysis to account for unserved energy or value of customer reliability; and
- SA Power Networks' Asset Management Plan stages duct replacements subject to budget availability. This demonstrates a lack of robust testing during the proposal stage.

The AER determined that SA Power Networks had not established that the North Terrace duct replacement project is prudent. Therefore, the proposed $10.0 million for the North Terrace Duct replacement project has not been included in the AER's substitute estimate for capex.

Our response and what we have done

We have taken into consideration the AER's feedback and would like to clarify that the North Terrace duct replacement program was not requested, nor approved in the 2015-20 regulatory proposal, nor any prior regulatory proposal.

Taking into consideration the AER's remaining feedback, we have revised our investment proposal in regard to the North Terrace duct replacement program. Our further work includes the development of a robust business case[32] that has assessed credible options and provides a cost-benefit analysis. Our assessment has determined that the planned delivery of this program is efficient and enables completion prior to future North Terrace works, which would significantly increase reinstatement costs for both planned and unplanned works.

Our revised forecast

SA Power Networks revised forecast for the CBD ducts and manhole program is $10.5 million as detailed in Table 8 below.

Table 8: Revised Proposal Forecast Expenditure ($2020, incl. overheads and escalators)

	2020/21	2021/22	2022/23	2023/24	2024/25	Total
North Terrace cable ducts	2.1	2.1	2.1	2.1	2.1	10.5

[32] SAPN revised proposal supporting document 5.7 and 5.7.1: North Terrace cable ducts business case and model.

4.5 Switchgear – Northfield Gas Insulated Switchboard

What the AER determined

The AER provided commentary on the approach used for determining forecast expenditure for the replacement of a critical 66kV Gas Insulated Switchboard (GIS) installed in 1988. The draft decision rejected our proposed forecast for the following reasons:

- SA Power Networks' independent engineering report indicated that short term interventions are likely to improve the likelihood of the existing GIS achieving its designed 'service life' and that these interventions can be reasonably achieved;
- SA Power Networks' preferred option assumes that the GIS will last until 2030 with short term interventions. This implies that the timing is not prudent;
- SA Power Networks is overstating the risk in its 'do-nothing' option as there was an assumption that the GIS would fail in the current regulatory control period, yet the GIS would be subject to the same interventions during the 2020–25 regulatory control period; and
- SA Power Networks has demonstrated that it is complying with reporting schemes and South Australian and Commonwealth legislation with regard to the release of sulphur hexafluoride gas (SF6), which is one of the risks associated with the condition of the GIS.

The AER determined that SA Power Networks did not establish that its proposed GIS replacement project is prudent. The AER have not included this project as part of the substitute capex estimate.

Our response and what we have done

We have taken into consideration the AER's feedback and would like to clarify the following:

- The Northfield GIS services 108,000 customers and its failure would result in tens of thousands of customers without supply initially, and a shortfall in capacity for approximately 16,000 customers during times of high demand;
- Replacing the GIS only once it fails exposes approximately 16,000 customers without supply at times of high demand for a period of 2 years while a replacement is built. There are no alternate or interim solutions that could mitigate the potential shortfall;
- The identified need to mitigate the reliability consequence is the rapidly deteriorating mechanical condition of the GIS;
- Multiple gas leaks have already occurred, and recent experience demonstrates that short term interventions have limited success, particularly for barrier board joints (4 failed attempts at leak repair);
- The majority of the proposed repex is to build a partial replacement only. That is, over half the repex to build a full replacement will be deferred beyond the next RCP. This partial replacement will mitigate the risk of unserved load at times of high demand. The existing GIS can then be run to failure with reduced reliability risk. No assumption is made for the exact timing of the GIS failure, only that the likelihood of failure is compounding every year as the external condition deteriorates;
- Despite SA Power Networks complying with reporting schemes in regard to the release of sulphur hexafluoride, the continued release of this insulating gas increases the likelihood of asset failure; and
- This project also forms part of SA Power Networks' commitment to environmental harm minimisation from the unchecked release of SF6 gas as the switchboard continues to deteriorate.

We have revised our investment proposal, taking into consideration the AER's feedback. Our further work includes:

- A cost-benefit analysis has been prepared, utilising sensitivity analysis of the discount rate, Value of Customer Reliability, GIS Failure Rate and the Cost of Gas Leak Repairs;
- We have updated our business case[33] with the latest findings and our additional work;

[33] SAPN revised proposal supporting document 5.6 and 5.6.1: Northfield GIS replacement business case and model

- Additional studies to determine the validity of assumptions regarding on-going interventions. As at July 2019, Hitachi advised that it is unable to provide the same repair solution and alternate options were investigated[34]; and
- Hitachi has offered a more invasive method of repair however; it is very costly and is associated with extremely high risks that can cause further/other damage to the infrastructure and increases exposure to supply outages from equipment unavailability.

We have revised our forecast for the Northfield GIS replacement project and believe we have provided information to address any shortcomings from our Regulatory Proposal.

Our revised forecast

SA Power Networks revised forecast for the Northfield GIS program is $11.8 million, consistent with our Regulatory Proposal and is detailed in Table 9 below.

Table 9: Revised proposal Forecast Expenditure ($2020, incl. overheads and escalators)

	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Northfield GIS	1.2	4.0	4.7	1.9	-	**11.8**

4.6 Switchgear – Circuit Breakers

What the AER determined

The AER observed that circuit breaker replacement expenditure largely drove SA Power Networks' modelled switchgear expenditure. The AER provided commentary on the approach used for determining forecast expenditure for the replacement program of circuit breakers. The draft decision rejected our proposed circuit breaker forecast for the following reasons:

- The total switchgear forecast expenditure is a step-up of 25 per cent from actuals over 2013–18 regulatory years;
- Circuit breakers replacement expenditure was the main driver for the increase, with a 38 per cent increase from actuals over 2013–18 regulatory years;
- Circuit breakers replacement volumes were determined using the CBRM model and therefore the general issues with CBRM as stated above in Section 3.1 apply to this expenditure; and
- Significantly overstated risk as calculated out to 2030 rather than 2025 even though risk calculated at 2025 is already overstated.

The AER determined that SA Power Networks has not demonstrated that its proposed replacement expenditure to mitigate circuit breakers risk in the 2020–25 is prudent and efficient. The AER substitute estimate for this asset group (circuit breakers) is based on 2013-18 historical average expenditure.

Our response and what we have done

We have taken into consideration the AER's feedback and would like to clarify the following:

- The use of 'maintain risk' CBRM modelling for substation switchgear remains our long-term strategy through this and the next regulatory control period;
- The Regulatory Proposal forecast appears to be larger than historical actuals because significant historical capital renewal has been hidden by high levels of load growth and augmentation investment in locations previously served by aged, high risk assets;

[34] Hitachi letter, Ref. SAPN-20190701-1, 1 July 2019

- The wider change in network investment drivers now require asset renewals to be substantially reliant on replacement expenditure to ensure safe and reliable service performance for customers;
- The change in replacement expenditure requirements have been increasing from mid-current period in response to significantly decreasing substation 'brownfield' augmentation expenditure since 2015-16;
- Over 2015 – 2020, we have undertaken a considerable program of refurbishment (life extension) across a population of circuit breakers that would otherwise require significant asset replacement repex i.e. Email/Westinghouse 11kV indoor circuit breakers;
- Circuit Breaker replacement projects are complex and have long delivery lead times, therefore planning on a 10-year timeframe is appropriate to program and prioritise critical assets that will have the greatest impact on risk reduction; and
- We maintain that using a 10 year forecast for long lived assets is prudent and the Revised Proposal forecast only contains expenditure required for the upcoming 2020-25 regulatory control period.

We have revised our investment proposal, taking into consideration the AER's feedback. Our further work includes the following:

- We have had our CBRM inputs independently verified[35];
- We have implemented most recommendations from the CBRM independent verification, including changes to values used for risk consequences and the likelihood of consequences occurring following an asset failure, and updated our CBRM results and replacement expenditure forecast (see Section 3.1);
- We have reviewed our modelled risks against actual risk incurred where data is available and adjusted our assumptions to align to actual risk; and

Our revised forecast

SA Power Networks revised forecast for the zone substation circuit breaker program is $58.1 million, $13.6 million higher than the AER substitute forecast of $44.5 million as detailed in

Table 10 below.

Table 10: Revised Proposal Forecast Expenditure ($2020, incl. overheads and escalators)

	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Circuit breakers	11.5	11.1	12.2	12.2	11.2	**58.1**

4.7 Transformers – Power Transformers

What the AER determined

The AER provided commentary on the approach used for determining forecasts for Transformer replacements. In particular, the AER focussed on the forecast replacement expenditure of zone substation transformers. The draft decision rejected our proposed forecast for the following reasons:

- The total transformers forecast expenditure is a step-up of 46 per cent from actuals over 2013–18 regulatory years.
- Zone substation transformers is 58% higher than historical spend.
- Zone substation transformer replacement volumes were determined using the CBRM model and therefore the general issues with CBRM as stated above in Section 3.1 apply to this expenditure.
- Risk has been overstated, calculating out to 2029 even though risk calculated at 2025 is already overstated.

[35] SAPN revised proposal supporting document 5.5: CutlerMerz, CBRM Model value of consequence independent report.

The AER determined that SA Power Networks had not demonstrated a need to increase its Transformers replacement expenditure in the 2020–25 over and beyond its actual current levels. The AER substitute estimate for Transformers is based on SA Power Networks' historical expenditure for Zone Substation Transformers across the 2013-18 period.

Our response and what we have done

The step-up in proposed forecast expenditure appeared to be larger than actuals because significant historical capital renewal has been hidden by high levels of load growth and therefore augmentation investment in locations previously served by aged, high risk assets. The wider change in network investment drivers now require asset renewals to be substantially reliant on replacement expenditure to ensure safe and reliable performance for customers. The change in replacement expenditure requirements have been increasing from mid-current period in response to significantly decreasing substation 'brownfield' augmentation expenditures. Substation power transformer replacement needs can vary significantly one period to the next and future requirements are unlikely to be represented by a 5-year historical average.

Similar to other CBRM modelled assets, the CBRM model results for power transformers are adjusted to account for augmentation projects that are planned for the 2020-25 regulatory period. This ensures we do not overstate the number of replacements required to maintain risk.

We have revised our investment proposal, taking into consideration the AER's feedback. Our further work includes the following:

- We have had our CBRM inputs independently verified[36];
- We have implemented most recommendations from the CBRM independent verification, including changes to values used for risk consequences and the likelihood of consequences occurring following an asset failure, and updated our CBRM results and replacement expenditure forecast (see Section 3.1);
- We reviewed our modelled risks against actual risks incurred where data is available and adjusted our assumptions to align to actual risk;
- We have reviewed our assumptions for oil loss risks in response to findings by the independent verifier and updated our model parameters so that forecast oil (environmental) risk aligns with historic experience; and
- Risk quantification using CBRM has now been updated using the latest asset input data up to 2018 where available and risk calculations out to 2030.

Our revised forecast

SA Power Networks revised forecast for the zone substation power transformer programs is $30 million, $11.3 million higher than the AER substitute forecast of $18.7 million as detailed in Table 11 below.

Table 11: Revised Proposal Forecast Expenditure ($2020, incl. overheads and escalators)

	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Power transformers	6.5	6.2	6.6	5.8	4.9	**30.0**

[36] SAPN revised proposal supporting document 5.5: *CutlerMerz, CBRM Model value of consequence independent report*.

4.8 Underground cables – Paper Insulated Lead Cables

What the AER determined

The AER provided commentary on the approach used for determining forecasts for underground cable replacements. In particular, the AER focussed on the forecast replacement expenditure of our paper insulated lead cables (PILC). The draft decision rejected our proposed forecast for the following reasons:

- The total underground cables forecast expenditure is a step-up of 636.5 per cent from actuals over 2013–18 regulatory years.
- The PILC replacement program was the main driver for the increase in underground cables expenditure.
- There appears to be a disconnect between the forecast and the outcomes of the engineering report produced to investigate the root cause of the higher than expected failures of these cables.
- Only 2.3km of PILC cables are identified with the highest probability of failure (PoF), yet the forecast aims to replace the entire population.
- The engineering report does not make recommendation to proactively replace cables.
- SA Power Networks have not provided any cost-benefit nor load at risk analysis to support its chosen volume of replacement.

The AER determined that SA Power Networks did not demonstrate that its proposed replacement expenditure forecast for underground cables was prudent and efficient. The AER substitute estimate for underground cables allows SA Power Networks to replace the 2.3 km that were identified, by SA Power Networks' consultant, to have the highest likelihood of failure.

Our response and what we have done

We have revised our investment proposal, taking into consideration the AER's feedback. Our further work includes the following:

- We are not planning on phasing out the entire PILC cable population, 61.5 kilometres of bare PILC cable will remain in service after the high risk cable sections are removed;
- The consultant Frazer-Nash was engaged to improve our level of understanding of how PILC cables fail and hence improve our understanding of the PoF of our PILC cables. They were *not* engaged to make recommendations on cable replacements.
- We have reviewed the sections of 11kV PILC identified by the Frazer-Nash report as having the highest PoF[37] across 8 feeders totalling 14.51km;
- We are not proposing any proactive replacement of lower risk PILC cables;
- We have undertaken a cost benefit analysis of these cable sections to compare the cost of cable replacement against the annualised risk cost (based on average annual load at risk) and annualised repair cost; and
- We have developed a business case[38] to account for the cost benefit analysis.

Our revised forecast

SA Power Networks revised forecast for the PILC cable replacement program is $7.1 million, $2.7 million higher than the AER substitute forecast of $4.4 million as detailed in Table 12 below.

Table 12: Revised Proposal Forecast Expenditure ($2020, incl. overheads and escalators)

	2020/21	2021/22	2022/23	2023/24	2024/25	Total
PILC	1.4	1.4	1.4	1.4	1.4	**7.1**

[37] FNC 57326 PILC UG Cable Asset Database Final Issue.xlsx which was data provided by Fraser-Nash to SA Power Networks as part of their submission of their 'Phase 2 PILC UG Cable Failure Final Report'.

[38] SAPN revised proposal supporting document 5.8 and 5.8.1: 11kV Paper Insulated Lead Cable replacement business case and model

5 Appendices

A. Document References

Table 13 lists the supporting evidence for the programs and projects in our Revised Proposal.

Table 13: Supporting documents

Document reference	Document name	Program it relates to
5.4	Repex Addendum	Repex
5.5	CBRM Model Value of Consequence Independent Report	CBRM Protection model
5.6	Northfield 66kV GIS Replacement Business Case	Northfield 66kV GIS
5.6.1	Northfield 66kV GIS Replacement model	Northfield 66kV GIS
5.7	North Terrace Cable Ducts Replacement Business Case	North Tce ducts
5.7.1	North Terrace Cable Ducts Replacement model	North Tce ducts
5.8	11kV Paper Insulated Lead Cable Replacement Business Case	PILC cables
5.8.1	11kV Paper Insulated Lead Cable Replacement model	PILC cables
5.9	Frontier economics - The long-run implications of regulatory repex allowances	Repex

B. CBRM modelled risk comparison

In response to the AER concerns regarding our CBRM forecast we engaged Cutler Merz to conduct an independent review of our CBRM methodology with emphasis on the value of consequences in the models (refer Cutler Merz independent validation – SAPN Revised Proposal supporting document 5.5: CBRM Model Value of Consequence Independent Report).

Several recommendations were made and as a result of this review and AER feedback we have made improvements to our models.

The economic value of consequences is now aligned with Cutler Merz recommendations and a comparison of the model risk outputs with our observed risk shows an alignment between observed actual risk and modelled risk.

We have compared modelled risk outputs with actual observed consequences to validate our models. All modelled risks are now comparable with observed risk noting that some risks (e.g. bushfire starts) are infrequent and therefore underrepresented in the observed risk values below.

Poles observed consequences compared with CBRM modelled risk 2018/19

2018-19 Actual consequence	Pole Break	Fire Start	Bushfire	Replacement	Plating
Network Performance	$ 4,920,264	$ -	$ -	$ -	$ -
Safety	$ -	$ -	$ -	$ -	$ -
Environment	Not measured	Not measured	Not measured	Not measured	Not measured
OPEX	$ -	$ -	$ -	$ -	$ -
CAPEX	$ 1,915,424	$ -	$ -	$ 20,932,990	$ 4,293,851

2018-19 Modelled risk	Pole Break	Fire Start	Bushfire	Replacement	Plating
Network Performance	$ 4,940,079	$ -	$ -	$ -	$ -
Safety	$ 867,326	$ 342,986	$ 362,683	$ -	$ -
Environment	$ 266,252	$ 40	$ 8,241	$ -	$ -
OPEX	$ -	$ 40,106	$ 381,492	$ -	$ -
CAPEX	$ 2,053,218	$ -	$ -	$ 17,005,346	$ 5,483,315

Circuit Breakers observed consequences compared with CBRM modelled risk 2018/19

2018-19 Actual consequence	Minor	Significant	Major	Condition Replacement	Fail to Trip
Network Performance	$ -	$ 1,462,446	$ -	$ -	$ -
Safety	Not measured	Not measured	Not measured	Not measured	Not measured
Environment	Not measured	Not measured	Not measured	Not measured	Not measured
OPEX	$ 537,784	$ 135,400	$ -	$ 13,468	$ -
CAPEX	$ -	$ -	$ -	$ 333,738	$ -

2018-19 Modelled risk	Minor	Significant	Major	Condition Replacement	Fail to Trip
Network Performance	$ -	$ 1,481,636	$ 635,490	$ -	$ 1,233,393
Safety	$ 190,748	$ 70,581	$ 167,312	$ 5,361	$ 92,710
Environment	$ 211,428	$ 11,064	$ 11,232	$ 9,530	$ 1,797
OPEX	$ 499,443	$ 44,486	$ 57,639	$ 69,045	$ 33,732
CAPEX	$ -	$ -	$ 279,151	$ 1,562,844	$ -

Zone Substation Power Transformers observed consequences compared with CBRM modelled risk 2018/19

2018-19 Actual consequence	Minor	Significant	Major	Condition Replacement
Network Performance	$ -	$ 683,108	$ 375,562	$ -
Safety	Not measured	Not measured	Not measured	Not measured
Environment	Not measured	Not measured	Not measured	Not measured
OPEX	$ 1,265,131	$ 63,250	$ 20,000	$ -
CAPEX	$ -	$ 75,000	$ 1,895,637	$ -

2018-19 Modelled risk	Minor	Significant	Major	Condition Replacement
Network Performance	$ -	$ 511,530	$ 249,239	$ -
Safety	$ 51,372	$ 45,317	$ 153,849	$ 2,121
Environment	$ 185,337	$ 41,816	$ 162,881	$ 47,230
OPEX	$ 1,198,691	$ 58,279	$ 44,423	$ 70,117
CAPEX	$ -	$ 11,557	$ 1,510,016	$ 2,225,535

There has not been a ‘Condition Replacement’ failure type in 2018/19 (given the small population of zone substation power transformers expenditure is not consistent annually), however the modelled output is consistent with the long-term trend.

Protection Relays observed consequences compared with CBRM modelled risk 2018/19

2018-19 Actual consequence	Minor/ Without Consequence	With Consequence	Spurious Trip
Network Performance	-	$ 856,000	$ 0
Safety	-	$ 0	-
Environment	-	$ 0	-
Bushfire	-	$ 0	-
OPEX + CAPEX	$ 926,043	$ 155,937	$ 0

2018-19 Modelled consequence	Minor/ Without Consequence	With Consequence	Spurious Trip
Network Performance	-	$ 320,510	$ 106,840
Safety	-	$ 51,800	-
Environment	-	$ 3,850	-
Bushfire	-	$ 36,260	-
OPEX + CAPEX	$ 741,140	$ 26,900	$ 8,970

C. Repex Model recommendations

We have reviewed the AER's approach to repex modelling of SAPN expenditure and would like to make the following recommendations for application of the repex model:

Exclusion of some categories of expenditure

In the AER's latest repex model, possibly due to low population and negligible repex spending in some categories in recent years, not all subcategories in modelled asset classes have been included, e.g. "UG cable >11kV" and several substation TFs lines appear to have been excluded. We recommend the AER include these lines in the repex model.

Treatment of Circuit Breaker expenditure

Repex modelling of SA Power Networks' "< = 11kV circuit breakers" in the Draft Decision has used a 'blended' intervention type that is not appropriate to forecast future repex requirements. SA Power Networks has historically separated 'business as usual' renewal expenditure from life extension (refurbishment) capex reporting in CA RINs to distinguish sustaining asset renewal programs from (often ad-hoc) investment in life extension programs that address specific design flaws or performance issues.

A blended intervention approach may present no material issue where the historical mix of is expected to continue into the future (e.g. pole staking/plating/replacement), however 11kV circuit breakers have been calibrated against a (one-off) program of life extension specific to Email/Westinghouse model indoor switchboard circuit breakers due for practical completion in 2020. Email/Westinghouse circuit breakers are the largest single population of oil insulated (1960 era) indoor circuit breakers in SA Power Networks' distribution network and the economies of scale and delivery of this program do not represent what is technically or economically achievable across the remainder of small make/model subpopulations of 11kV circuit breakers reaching end of life over 2020-2025.

Our suggested approach to modelling 11kV circuit breaker repex is to consider 'refurbished' Email/Westinghouse circuit breakers as a sub population of 11kV circuit breakers using historical replacement unit costs and a relative age at replacement (estimated life extension) of +15 years.

Treatment of Switch expenditure

For "Switch" lines under "Switchgear", NEM's median unit costs are substantially lower than SAPN's unit costs. This is possibly due to lower unit cost OH distribution switches reported under these categories by some DNSPs where we have only reported (higher unit cost) zone substation switches under these categories and reported our distribution OH switches (such as fuses, air breaks, load switches) under "Pole top structures". Therefore, it is not appropriate to benchmark our zone substation switches alone with the NEM's median which is a blend of distribution and zone substation assets. As a result, we recommend the AER use historical scenario or other similar benchmark for our zone substation switches.

In the AER's latest repex model, our distribution switching cubicle has been categorised as ">11kV & <=22kV switch". Like switches above, NEM's median unit cost is substantially lower than SAPN's unit cost and NEM's median mean life is substantially higher than SAPN's mean life. This is possibly due to lower unit cost OH distribution switches being reported under these categories by some DNSPs where we have only reported distribution switching cubicles in this category and reported (lower unit cost) distribution OH switches (such as fuses, air breaks, load switches) under "Pole top structures". Therefore, it's not appropriate to benchmark our distribution switching cubicle alone with the NEM's median which is blended of ground level and overhead distribution assets. As a result, we recommend the AER use historical scenario or other similar benchmark for our distribution switching cubicles.