30 November 2023

Ausgrid's 2024-29 Revised Proposal

Attachment 5.4: Replacement

Empowering communities for a resilient, affordable and net-zero future.

Ausgrid

Contents

1. Introduction

1.1 This document's purpose

This document provides an addendum to forecast replacement expenditure (**repex**) for Replacement Programs and Major Projects. These form part of Ausgrid's overall forecast of standard control capital expenditure (**capex**) for the 2024-29 Regulatory Control Period (**2024-29 period**). This document should be read in conjunction with Ausgrid's **Attachment 5.1 Proposed Capital Expenditure**.

1.2 This document in context

This document includes the scope of replacement programs only. This does not include replacements covered under:

- Operational Technology & Innovation (refer to **Attachments 5.8**, **5.8.2**, **5.8.4** and **5.8.e**), and
- Climate Resilience (refer to **Attachment 5.5**).

1.3 Related documents

Att #	Document
5.1 (Revised Proposal)	Proposed Capex
5.2.c (Initial Proposal)	Customer Value Framework
5.4.a (Initial Proposal)	Asset Replacement Programs
5.4.b (Initial Proposal)	Major Projects - 11kV Switchgear Replacement
5.4.c (Initial Proposal)	Major Projects - Sub-transmission Cable Replacement
5.4.d (Initial Proposal)	Major Projects – Other Replacement
5.4.e (Initial Proposal)	CBA Approach for Replacement Programs
5.5 (Revised Proposal)	Climate Resilience Program
5.8 (Revised Proposal)	Network Innovation Program
5.8.2 (Revised Proposal)	Control System Core Refresh Program
5.8.4 (Revised Proposal)	Operational Technology Security Program
5.8.e (Initial Proposal)	Network Digitisation Program
6.2 (Initial Proposal)	Network Maintenance Program

1.4 Document overview

To maintain a safe and reliable service to customers, existing infrastructure is required to be carefully managed. This includes the replacement of assets at, or approaching, end of life. Replacement Programs include the replacement of individual assets with assets that perform the same function in-line with current standards. Major Projects combine multiple Replacement Program needs into a single project. These expenditure activities may also include life extension or rearrangement activities such as asset refurbishment and network consolidation.

This document describes the assessment undertaken to form the revised Replacement Programs and Major Projects expenditure forecast for standard control asset classes during the 2024-29 period. It includes an explanation of the high-level economic evaluation methods used to form this forecast as well as the risks, option analysis and asset management strategies associated with key asset classes.

2. Response to the Draft Decision

Summary of how we have responded to the Draft Decision

	Project summary
Replacement Programs & Major Projects	Repex includes the replacement or life extension (renewal) of network assets. This section includes details related to recurrent Replacement Programs and Major Projects. A Major Project combines multiple Replacement Program needs into a single project where it is deemed efficient from a broader network assessment. For example, replacement of two sub-transmission cables with a single higher capacity cable.

	Initial Proposal	Draft Decision	Revised Proposal
Replacement Programs	$1,195m	$1,107m	$1,138m
Major Projects	$251m	$251m	$290m
Total	$1,446m	$1,358m	$1,428m

	Why our Revised Proposal meets the needs of customers
Our revised proposal is: • **5% more than the Draft Decision** • **1% lower than our Initial Proposal**	The Revised Proposal incorporates changes in bottom-up forecasts since the initial proposal and feedback from the AER Draft Decision. An update to unit rates supports a reduction in our Dedicated Low Voltage (**LV**) Mains program partially off-set by increases in forecast updates. Both the modelled and unmodelled components of our forecast remain lower than our cost benefit analysis (**CBA**) outputs, the current period forecast and the AER Repex Model. The Revised Proposal for repex represents a prudent and efficient forecast that is expected to deliver consistent safety and reliability outcomes while acknowledging customer priorities and affordability concerns.

	How we have responded
Reduction in Dedicated LV Mains	To support our revised Dedicated LV Mains program, we have reduced our forecast unit rate and provided a detailed business case which supports the veracity of the model inputs, sensitivity and options analysis. Our revised forecast of $80 million is $63 million lower than our Initial Proposal of $143 million. For more information refer to **Section 4**.
Other changes leading to increases across the portfolio	Since our Initial Proposal, new information has led to changes in the mix of forecast replacement: • Flow on impacts from TransGrid protection work requires an increase in protection systems upgrades ($5 million additional). • Updated customer expected unserved energy and costs has brought forward investment for some Major Projects ($13 million additional). • Updated condition information in driving a change in solution from program-based replacement to a Major Project. ($21 million additional).

3. Replacement Expenditure

3.1 Revised asset replacement expenditure

Ausgrid's total repex consists of:

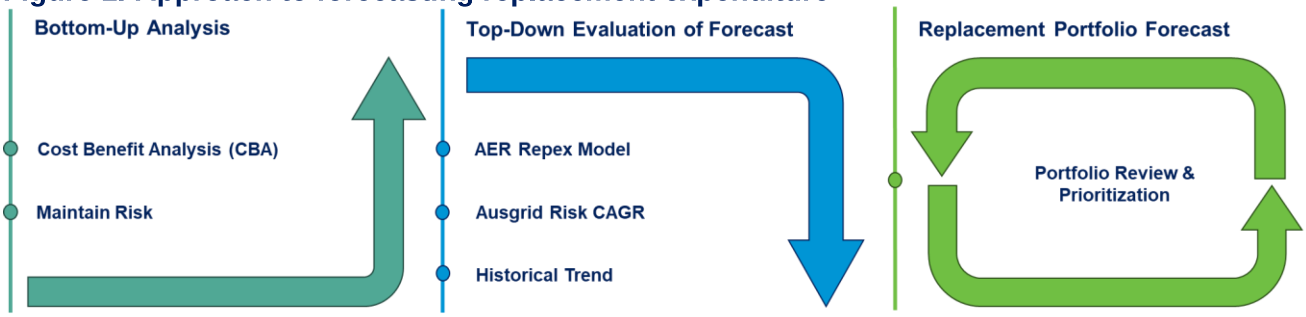
- Replacement Programs (refer to **Section 4**),
- Major Projects (refer to **Section 5**),
- Operational Technology and Innovation (OTI) (refer to **Attachments 5.8**, **5.8.2**, **5.8.4** and **5.8.e**); and
- Climate Resilience (refer to **Attachment 5.5**).

This attachment is focused on Replacement Programs and Major Projects totalling $1,428 million. OTI and Climate Resilience are detailed in other attachments.

3.2 Process for Assessment

Ausgrid's repex forecast has been developed through the application of multiple forecasting methods. The use of multiple forecasting methods supports the development of a replacement forecast that is prudent and efficient. The following approach was taken to establish Ausgrid's replacement proposal:

Figure 1. Approach to forecasting replacement expenditure



What we heard	How we've responded
The AER commended the improved quantitative analysis, decision-making governance and analytical tools. They concluded that the majority of the recurrent investment capex was reasonable, other than dedicated LV circuit reconfiguration.	We noted the specific concerns raised with our Dedicated LV Mains program and have undertaken a detailed review, resulting in a lower forecast for this program. This is supported with a detailed business case captured within this document.

A top-down evaluation was used to challenge our bottom-up forecast. This included applying a range of top-down tools as shown in **Figure 1**.

For further details on the CBA methodology used to support the development of the repex forecast refer to ***Attachment 5.4.e CBA Approach for Replacement Programs*** and ***Attachment 5.4.f CBA Approach for Major Projects.***

We have not changed our approach to applying quantitative bottom-up and top-down analysis. Our updated replacement expenditure forecast reflects new information since the initial proposal, including load forecasts, estimated costs and new information on the feasibility of in-situ switchgear replacement.

3.3 What has changed from our Initial Proposal

Our revised Replacement Programs and Major Projects repex forecast of $1,428 million is an overall reduction of $18 million from the Initial Proposal. Following COVID, FY23 represents the most stable year of the current 2019-24 period and therefore reflects a higher forecast across all top-down evaluation methods. Our top-down evaluation methods have been updated with FY23 expenditure.

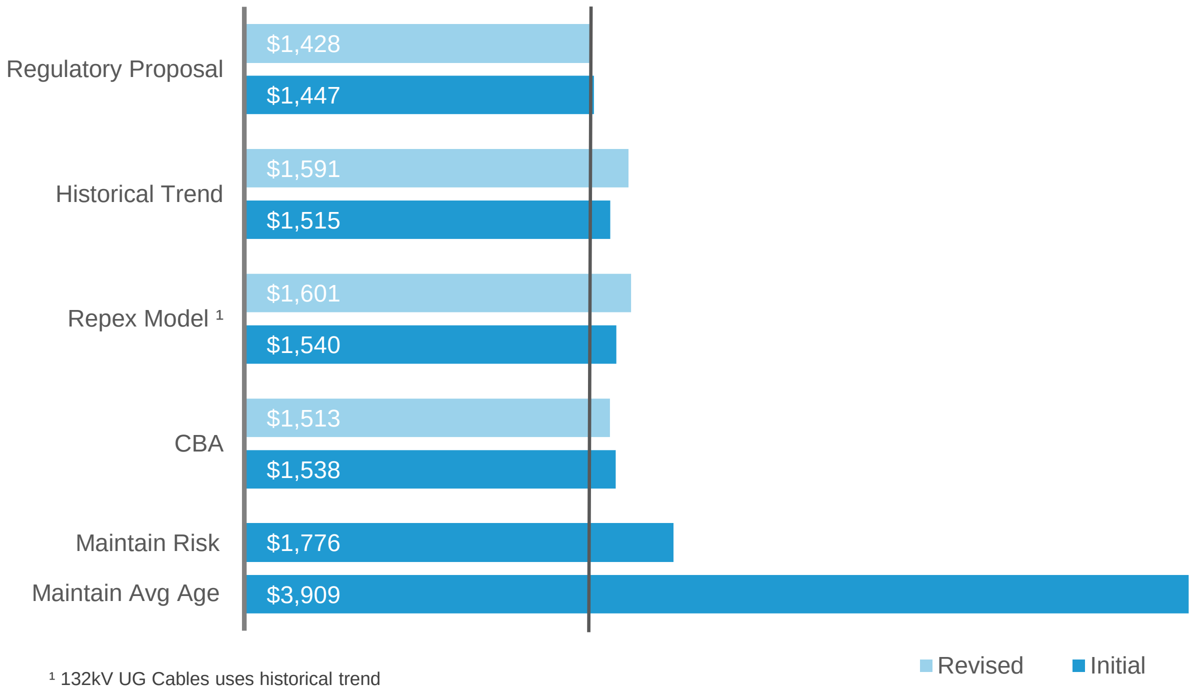
From this evaluation, our forecast is:

- $85 million lower than the forecast supported by our CBA
- $163 million lower than the forecast expenditure for this period, and
- $173 million lower than the most likely scenario selected by the AER as per the AER REPEX Model.

This forecast is also lower than both the modelled and unmodelled components of the AER REPEX Model for scenario 1 and 3 and only slightly above scenario 2.

Figure 2 shows our forecast for each forecasting method, comparing our Initial Proposal against the Revised Proposal.

Figure 2. Ausgrid's forecast against alternate forecast methods (real $m, FY24)[1]



Changes since the initial proposal include:

- TransGrid's[2] committed replacement of protection systems on Ausgrid feeders connecting to two of their bulk supply points. This will require work to be carried out at the respective Ausgrid feeder ends so the protection systems are compatible. Coordination work between Ausgrid and TransGrid since the Initial Proposal has identified a requirement for an additional $5 million repex forecast.
- Updated load forecasts show increased electricity demand in some load centres. This impacted the risk carried and required replacement timing of the Major Projects for the Drummoyne 132kV cables and associated 132kV switchgear (refer to **Section 5.1**) and the Paddington 33kV cables (refer to **Section 5.2**). These changes represent an increase of $7 million and $6 million respectively since the Initial Proposal.
- The Initial Proposal included $3 million for 33kV circuit breaker replacements. A review of the feasibility of these replacement works and examination of options to minimise long-term cost to customers of replacing the 33kV oil insulated circuit breakers at Merewether sub-transmission substation (**STS**) has led to a change in forecast works required in the 2024-29 period. This was driven by the condition issues associated with the wall bushings and building, and constraints associated with the existing building. Our updated analysis supports the replacement of the switchgear and building for an estimated cost of $24 million (refer to **Section 0**). Expenditure previously included for 33kV circuit breakers replacement has been removed.
- A reduction of $63 million in the Dedicated LV Mains program in-line with an updated (lower) unit rates. These unit rates are more reflective of historical costs.

A summary of these changes are shown in the table in **Figure 3** below.

[1] DNSP RIN data to determine the REPEX Model outcome (incl FY23 actuals) is not available to Ausgrid yet, this reflects an indicative scenario based on extrapolating 3 years of data for other DNSPs.
[2] https://www.aer.gov.au/system/files/AER%20-%20Transgrid%202023-28%20-%20Final%20Decision%20-%20Attachment%205%20Capital%20expenditure%20-%20April%202023.pdf

Figure 3. Changes to the Replacement investment since the initial proposal (real $m, FY24)

	FY25	FY26	FY27	FY28	FY29	TOTAL	Initial Proposal
Dedicated LV Mains	16	16	16	16	16	**80**	**143**
Protection Systems	2	2	2	2	3	**12**	**7**
132kV Fdr 202	0.2	1	6	8	2	**18**	**17**
132kV Fdr 203 & 204	1	4	16	23	6	**50**	**46**
Drummoyne 132kV SG	0.3	2	4	6	2	**15**	**13**
Paddington 33kV Fdrs	0	0	0.1	1	4	**6**	**0**
Merewether 33kV SG	0.2	3	8	8	4	**24**	**0**
33kV switchgear	0	0	0	0	0	**0**	**3**
Total	**20**	**29**	**53**	**66**	**38**	**205**	**229**

These changes highlight the operational trade-offs that are common with a bottom-up replacement forecast. It is therefore important when forecasting recurrent replacement that a combination of bottom-up and top-down forecasting is applied. This enables key risks and customer benefits to be targeted, while allowing for trade-offs if emerging risks and / or opportunities arise during the period, requiring higher priority attention.

Our Revised Proposal reflects a position that is supported by a range of forecasting methods, while prioritising customer affordability.

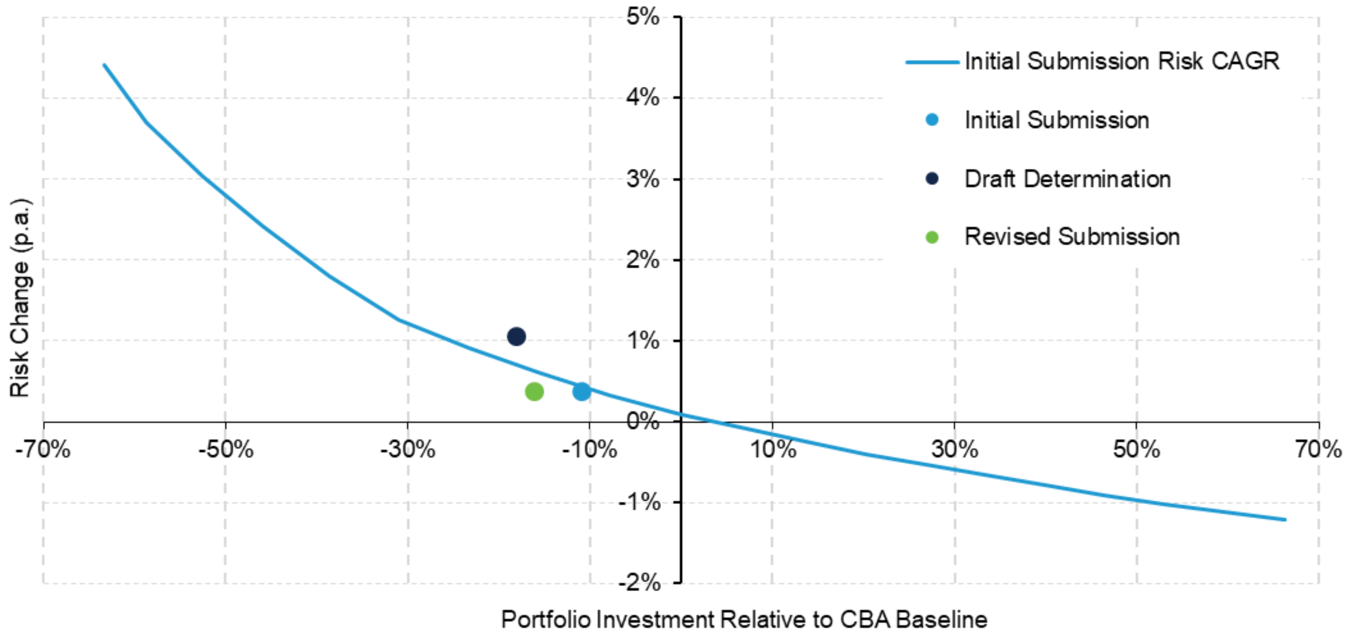
3.4 Forecast growth in carried risk

Forecast growth in carried risk is measured via Compound Annual Growth Rate (**CAGR**) indicator measuring the degree to which carried risk associated with our asset base is increasing or decreasing.

From the Initial Proposal, the risk was forecast to grow by approximately 0.4% per annum, or approximately 2% over the 2024-29 period (shown where the blue line in **Figure 4** crosses the dotted line). In this scenario, the risk would double in magnitude over 165 years.

If Ausgrid were to adopt the investment portfolio aligned with the AER's Draft Decision the risk would be expected to grow by approximately 1% per annum, or approximately 5% over the 2024-29 period (shown where the green line in **Figure 4** crosses the dotted line). In this scenario, the risk would double in magnitude over 69 years.

Figure 4. Annual replacement program expenditure Risk CAGR sensitivity



The risk CAGR analysis has the following assumptions:

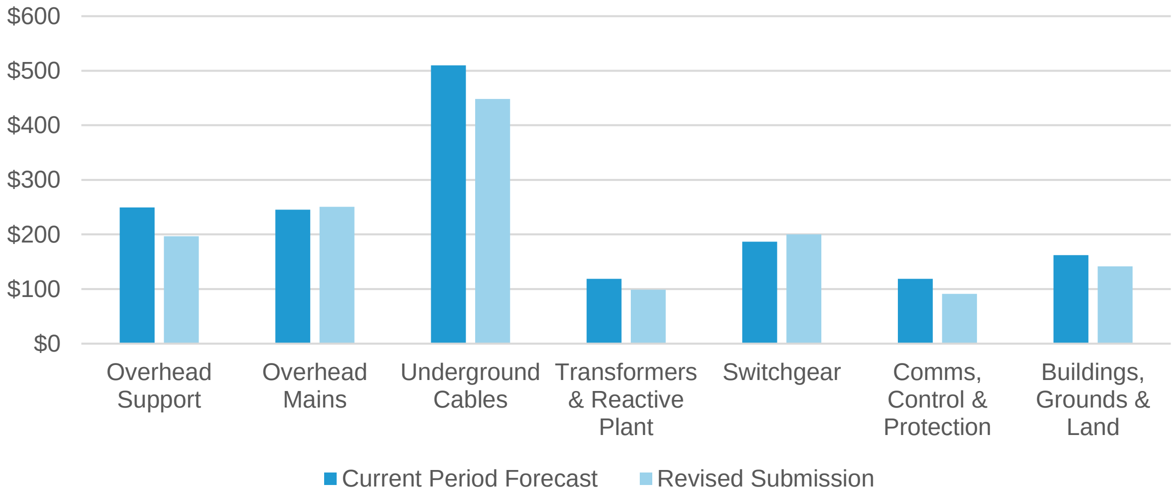
- It is established by rolling up individual asset investments and programs of work.

- That assets with the highest CBA ratio will always be prioritised for removal first. Noting this may not always hold true in practical scenarios.
- A grossly disproportionate factor (GDF) is applied to safety risk when evaluating the appropriate timing of individual investments that make up the bottom-up forecast, but is excluded from this overall risk CAGR metric as it is not an evaluation of the timing of an individual replacement decision.

3.5 Historical trend analysis

The revised repex forecast for the 2019-24 period is $1,428 million which overall is lower than the forecast for the current 2019-24 period of $1,591 million. **Figure 5** compares our revised forecast to our current period forecast by asset class inclusive of Replacement Programs and Major Projects. With the changes made in the Revised Proposal, the expenditure across asset classes is not significantly different between the current 2019-24 and 2024-29 periods, further supporting the expected recurrent investment.

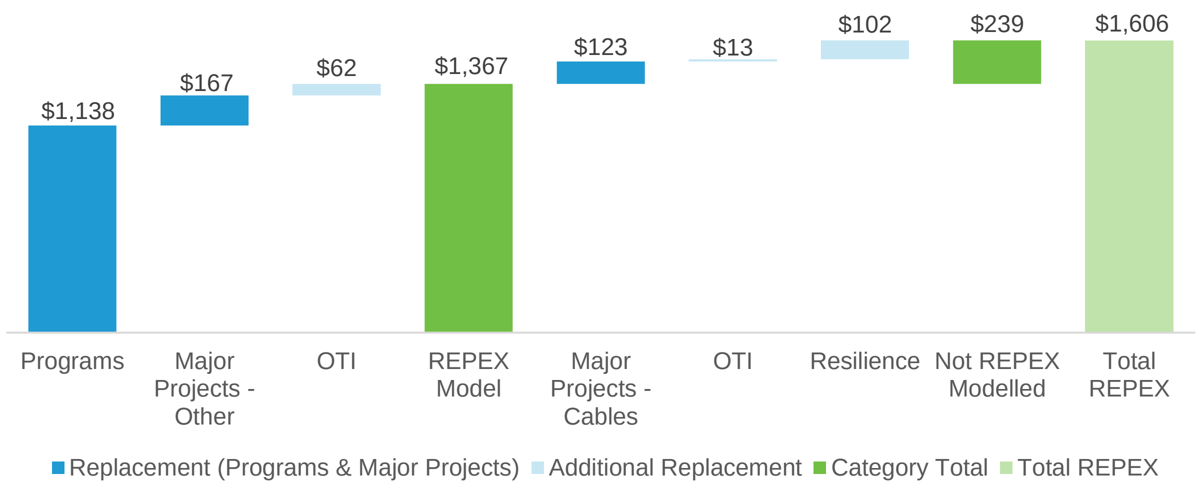
Figure 5. Asset Class revised forecast compared to 2019-24 forecast expenditure (real $m, FY24)



3.6 Updates to the AER Repex Model

Following the Initial Proposal, the AER Repex Model has been updated to include the actual expenditure for FY23. Since we do not have RIN data from other distributors, for benchmarking only, Ausgrid FY23 data was included. As per the Initial Proposal, not all repex is included in the AER Repex Model, as shown in **Figure 6** below:

Figure 6. AER Repex model inclusions by category (real $m, FY24)

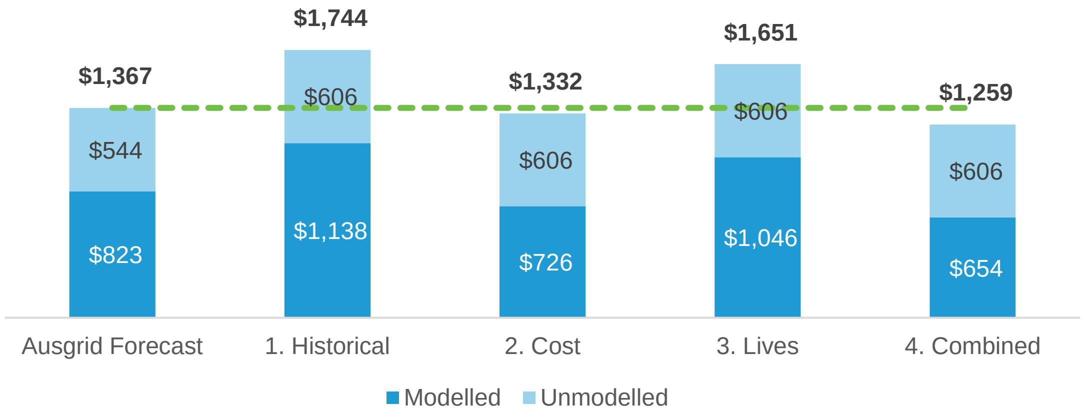


3.6.1 Evaluation of revised replacement program expenditure against Repex Model

The AER Repex Model was used to evaluate the replacement forecast against industry benchmarks and regulatory standards, providing insights into our prudency and efficiency. In evaluating the replacement program:

- The component that is within the scope of OTI, shown in **Figure 6** as $62 million, has been included in the AER Repex Model analysis for consistency.
- Inclusion of the FY23 actual expenditure has resulted in an increase to the AER Repex Model forecast compared to the Initial Proposal.

Figure 7. Ausgrid forecast expenditure vs. preliminary 4Y Repex Model (real $m, FY24)



Overall, Ausgrid's replacement forecast in scope of the AER Repex Model compares favourably to the analysis Ausgrid has conducted in **Figure 7**:

- Considering the expenditure categorised as Modelled, Ausgrid's forecast is $823 million in comparison to AER Repex Model projections of between $654 million and $1,138 million.
- Unmodelled forecast of $544 million is lower than the calculated historical trend of $606 million.

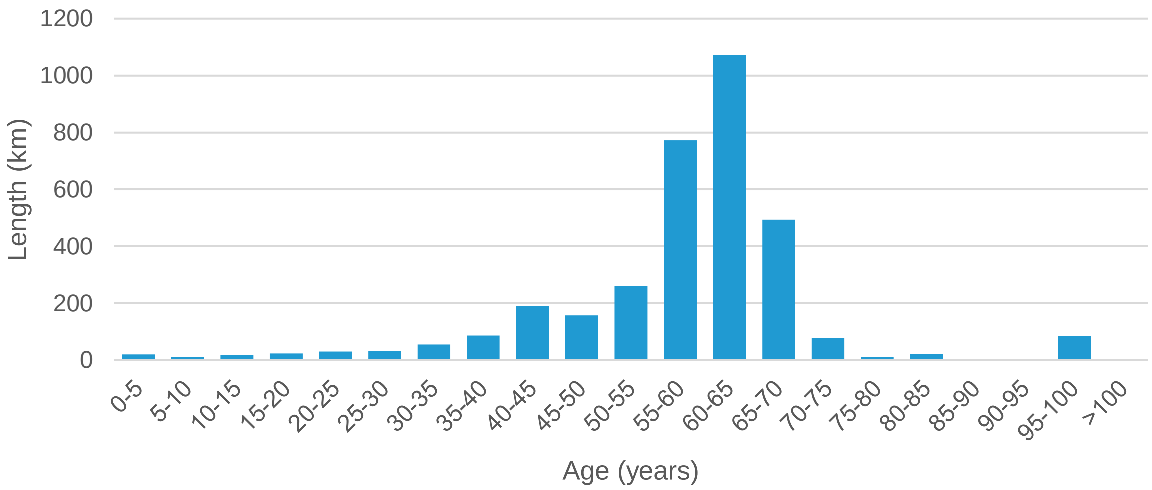
The Dedicated LV Mains program is included in the Unmodelled forecast of the AER Repex Model. Despite the increase in this one program, the overall forecast remains lower than the calculated historical trend for Unmodelled repex. This highlights the importance of and supports the trade-offs made in developing the forecast to manage this emerging risk.

4. Dedicated LV Mains Business Case

4.1 Introduction

Ausgrid's LV distribution network was originally designed with separate dedicated street light circuits (dedicated LV mains). These circuits were generally constructed with bare, small diameter conductors and utilised a central control mechanism to switch the circuit on at nighttime. These circuits were constructed above or below low voltage distribution circuits (**LV distributors**) depending on the geographical area. The age profile of these assets is shown in **Figure 8**.

Figure 8. Age Profile for Dedicated LV Mains



A fatality on another network in 2011 was the result of a dedicated street light conductor failing and a member of the public contacting the fallen energised conductor[3]. In response, a review of the risks posed by this asset was undertaken and concluded:

1. Conductors used for dedicated circuits are a thinner construction and therefore more likely to fail than conductors used for other LV distributors under the same conditions.
2. There is a lower likelihood that a failure of conductors on dedicated circuits will be reported as they do not supply customer homes. This may be less likely as streetlights are converted to modern lights which do not depend on the circuits for supply.

As a result of this fatality, the Dedicated LV Mains program was initiated during the 2019-24 period. Ausgrid has since observed multiple safety incidents and high potential near misses on our network resulting from dedicated street light mains conductor failures. A recent near miss was also reported in the news[4]. In this instance the mains were not live. A review of outage data highlighted instances where contact with the low voltage led to an outage on the low voltage distributor below the dedicated mains.

[3] https://www.watoday.com.au/national/western-australia/family-left-numb-after-teen-girls-tragic-electrocution-20110131-1aa7o.html

[4] https://www.dailytelegraph.com.au/news/nsw/live-wire-attached-to-metal-pole-in-st-ives-was-a-death-trap/news-story/87efd514e23e21cef9e18f2d198c3f07

What we heard	How we've responded
The AER noted that a safety incident and an outage should be mutually exclusive.	In review of the data, we found in some circumstances this was not the case i.e. emergency unplanned outage on safety grounds. However, the impact of this was minor and therefore we support this position for modelling purposes and have reviewed our data to confirm that no such overlap exists.

The public safety risk remains a concern for Ausgrid, however, with the values applied to both customer reliability and public safety, the analysis supports a larger benefit contribution from the avoided unserved energy experienced by customers, and therefore a higher forecast expenditure relative to the current 2019-24 period.

4.2 Asset Performance – our lived experience

The inherent risk and benefits profile associated with our replacement programs, including Dedicated LV Mains, are determined from Ausgrid's lived experience (historical events) over the previous 5-year period (FY17-21). Our CBA approach seeks to maximise the benefits at both a portfolio and individual program level to ensure a prudent and efficient investment envelope. Refer to ***Attachments 5.4e - CBA Approach for Replacement Programs*** and ***5.2.d - Principles of CBA*** for a detailed breakdown and methodology.

As outlined in each section below, we undertake veracity and reasonableness tests for each parameter along with validating that, when combined, they reflect an appropriate and reasonable baseline.

In our analysis, we have only considered situations where there is either an outage, safety incident, or fire start event for the total number of expected failures to ensure modelled risk per event does not exceed that experienced historically experienced.

4.2.1 Determining our base failure rate

Our historic failure data is matched to an asset class and then down to an individual asset in accordance with ***Attachment 5.4e - CBA Approach for Replacement Programs***.

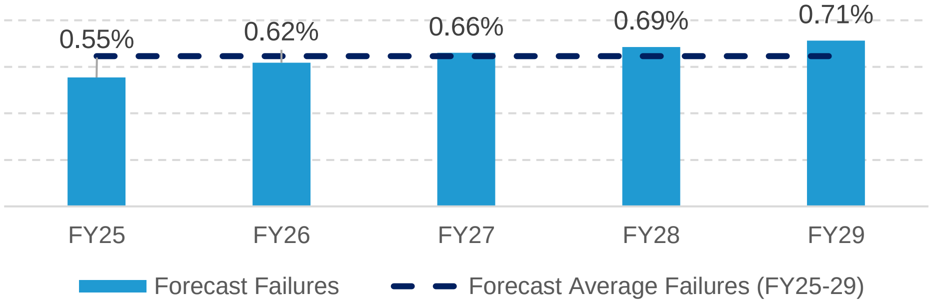
To ensure the forecast model reflects a reasonable volume of annual failures, the prediction is normalised to the historical asset performance by setting the base year failures to be the average failure rate (lived experience) across the last 5 years. We then test multiple scenarios to further ensure the reasonableness of modelled parameters and our CBA baseline - this is done at the individual asset sub-class, asset class and the portfolio level. A breakdown of observed failure modes is presented in **Figure 9** below.

Figure 9. **Dedicated LV Mains Failure Modes**

Asset Sub-class	Part Description	Failure Mode Description	Failures
Dedicated LV Mains	Conductor insulator attachment tie	Detached from pin type insulator	0.86%
	Conductor termination	Broken / damaged	0.25%
	Conductors (phase, earth or both)	Broken / damaged	98.90%

We reviewed the base year failures both for these dedicated LV mains as well as for the broader Overhead Mains asset class to further validate the reasonableness of our base year failures as per **Figure 10**.

Figure 10. Forecast inherent failures as a proportion of the population for dedicated LV mains



Our base failure forecasts are presented below in **Figure 11**.

Figure 11. Base failure forecasts

Asset Sub-class	Failure rate increase (2025-29)	Conditional Failure Count (FY22 Base Year Failures)
Dedicated LV Mains	6.5%	640

To test the veracity of these values we have considered:

- Maintaining failures at the forecast average for the 2024-29 period would result in a replacement period of 51 years.
- Replacing assets on failure (base case), based on the projected growth past FY29, it would take 33 years for the entire population to be reactively replaced.

Given the mean age of our remaining dedicated LV mains is approximately 60 years, we consider the predicted failures during the period to be reasonable.

4.2.2 Setting the Probability of Event

We have validated that the total Probability of Event (PoE) across all consequence categories contributing to the inherent risk profile for dedicated LV mains does not exceed 100%, which could indicate the possibility of concurrent events and potential double counting. Our combined consequence parameters are presented in **Figure 12** below.

Figure 12. Dedicated LV mains PoE parameters

Consequence Category	Probability of Event
Loss of Supply	86.4%
Public Safety	8.1%
Worker Safety	1.3%
Fire	0.1%
Total	95.7%

4.2.3 Determining our baseline historic safety performance

Historical safety events are categorised and analysed in accordance with ***Attachment 5.4e - CBA Approach for Replacement Programs***. Ausgrid undertakes a detailed review of the historic safety incident data to provide a level of assurance that it has been accurately captured and assigned to the correct asset type. Whilst Worker Safety is captured, its contribution to dedicated LV mains, based on recent lived experience, is negligible so we have focused below on the key risk driver being Public Safety.

Our historical safety data informs both our incident frequency and severity which establishes the baseline PoE & Probability of Severity (PoS) parameters within each model.

Within the current 2019-24 period we have observed several safety incidents and high potential near misses on our network due to failures of these mains. Whilst high potential near misses, including a member of the public contacting and moving a fallen dedicated LV mains conductor[5], were included in the baseline they are weighted and capped in accordance with ***Attachment 5.4e*** at a total contribution of 1 ‘insignificant’ incident. Our modelled public safety parameters are presented in **Figure 13**.

To accurately reflect the high potential severity incidents we observed, we have further reviewed the approach for the PoS distribution. This involved running sensitivity analysis on the ‘years to event’ baseline for the model to more accurately reflect the risk associated with fallen conductors to the public as observed by Ausgrid and other DNSPs noting the 2011 fatality.

Figure 13. Dedicated LV mains public safety severity distribution (years until event in base year)

Consequence Category	Insignificant	Minor	Moderate	Major	Significant
Public Safety	0.02	5	20	50	100

4.2.1 Determining our baseline historic outage performance

A recent investigation into the 2021 high potential safety incidents led to a deeper review of all data, including the investigation of the circumstances which prevented a serious injury. At this point, it was found that in many cases (but not all), the LV distributor adjacent to the dedicated LV mains was isolated either via the fuse in the substation or under emergency ‘make safe conditions’ leading to customer outages and minimising the public safety risks.

[5] https://www.dailytelegraph.com.au/news/nsw/live-wire-attached-to-metal-pole-in-st-ives-was-a-death-trap/news-story/87efd514e23e21cef9e18f2d198c3f07

Ausgrid analyses and aligns our historic outage performance data from our outage management system (OMS) system and to a corresponding asset type by undertaking a ‘deep dive’ on the data to ensure accuracy. In total, 85 loss of supply events attributable to dedicated LV mains conductor failures were realised during the FY17-21 period.

The average LV distributor expected unserved energy (EUE) value is applied to the dedicated LV mains model in accordance with ***Attachment 5.4e*** and ***Attachment 5.2c***. We consider this to be reasonable as our lived experience is shared across the overhead mains asset class and validated at both the sub class and asset class levels.

What we heard	How we’ve responded
The AER raised concerns that our modelling assumes nearly all dedicated LV circuit conductor failures cause an outage to all 3 phases in the shared LV network.	We agree that there will likely be a range of circumstances where a single or all three phases realise an outage. We have reviewed our modelling and can confirm that by using the lived experience of individual customers in determining the unserved energy, we have accounted for these scenarios.

4.2.2 Application of grossly disproportionate factor

Ausgrid applies a grossly disproportionate factor (GDF) based on the severity of the safety consequence, ranging from 2 for insignificant and 10 for significant. The value of 10 reflects an order of magnitude difference, which is a common risk management practice.

What we heard	How we’ve responded
The AER raised concerns regarding our application of GDF and overstating of safety risk, referring to their Replacement Expenditure guideline which recommends the application of 3x for workers and 6x for public.	We have applied sensitivity testing utilising the Replacement Expenditure guideline recommended figures and can confirm the difference between Ausgrid’s approach and the Replacement Expenditure guideline is negligible. This is the result of safety events being skewed towards insignificant severities where the GDF is lower.

4.2.3 Variances between our CBA model and the submitted Excel version

We appreciate that our replacement CBA model, due to its inherent complexity and scale, may be difficult for the AER to engage with. To support a prudent and thorough review by the AER we reverted to our previous excel-based model used for our 2019-24 period. While we stand behind the output of the CBA model, there are several complex calculations being undertaken at an individual asset level to establish unique risk growth curves based upon individual asset attributes that enables granular modelling and economic evaluation to take place.

This approach improves the effectiveness of failure predictions and enables us to better determine the most prudent investment portfolio, however, is beyond the calculation capabilities of Excel. As a result, we have provided a simplified Excel-based model. Variations between the two models include:

- Due to the size and complexity of the data models involved, the same level of risk segmentation in our granular span-by-span CBA modelling could not be applied in the Excel version of the CBA model. To enable processing in excel we have had to apply averages to some inputs and aggregated the population into groupings.
- The CBA model uses the Pheonix RapidFire Fire Simulator to determine the predominant landscape-scale fire risk outcomes starting from areas within Ausgrid’s supply network. The Pheonix model supports a more granular spread of fire risk based on the location and unique attributes of each individual asset. We were unable to repeat this analysis for the Excel version of the CBA model and have instead, relied upon an average fire risk per asset.

4.3 Application of unit rates

Since the Initial Proposal and from discussions with the AER, we have explored options to further refine our proposed unit rates for the program based on our top-down challenge on our overall replacement program.

The delivery strategy to date for this program has been to target and prioritise ‘under-built’ construction and focus on areas requiring minimal network outages and planning. Due to the relative simplicity of the field work involved this resulted in a unit cost which was lower than the bottom-up unit rate used in the Initial Proposal.

The next phase of the program is primarily targeting 'over-built' dedicated LV mains construction and also more complex circuits (i.e. circuits cross multiple LV, HV, TR feeders). This scope requires multiple network isolations to enable us to safely manage the overbuilt mains. This increased complexity was reflected in our forecast unit rate.

As part of our top-down challenge we have aligned our forecast unit rate more closely to our historical unit cost. We will monitor the impact as project complexity increases through the 2024 – 29 regulatory period.

What we heard	How we've responded
The AER raised concerns with our increased unit rates when compared to historical program actuals.	In response, we have applied a lower unit rate to our forecast, which has resulted in an overall reduction to our forecast expenditure. This in effect applies an inherent delivery efficiency target that will need to be closely monitored throughout the 2024-29 period.

4.4 Other investment options considered to mitigate the risk

Since the Initial Proposal and from discussions with the AER, we have tested alternative investment options, to validate the solution that has been adopted.

What we heard	How we've responded
The AER noted the lack of options analysis included in our proposal.	We acknowledge this gap and have provided additional information on the options we have considered.

To validate the options, we updated our CBA and evaluated the average benefit to cost ratio (**BCR**). The preferred option is the one that provides the highest average BCR.

Figure 14. Average benefit to cost ratio (FY24-29)

Option	Replacement	Neutral Bonding	Reconfiguration
Average BCR	1.34	1.39	1.46

4.4.1 Base Case Scenario - replace on failure / 'do nothing'

Given the customer and safety risks being managed, a base case scenario would include, as a minimum, the reactive management in the event of a failure. In considering this option we evaluated replacement / reconfiguration following failure and 'opportunistic replacement' with other drivers, namely pole replacement.

1. ***Replace / reconfiguration following failure:*** this was excluded as a viable solution due to the projected growth in failure rate, increased cost of reactive works, safety risk and unserved energy to customers as supported by our cost benefit modelling. This option would only be adopted when the cost of alternative options outweighs the benefits i.e. when mains outside the scope of the proposed program were to fail.
2. ***'Opportunistic replacement' as part of pole replacements:*** pole replacements are often done with the network remaining in-service. The operational risks associated with this program requires an outage on the associated feeders. Furthermore, once spans are removed on either side of a pole, new terminations will need to be established on each pole either side of the pole being replaced, increasing the probability of failure of the remaining circuit that has now been modified. As a result, this option would increase the cost to customers, reducing the efficiency and prudency of the replacement of poles and the Dedicated LV Mains program.

4.4.2 Like for Like replacement

Applying like for like replacement will reduce the probability of failure, relative to the base case. In evaluating this option the average BCR is positive, supporting this solution over the base case option. However, this option carries a higher cost and higher residual risk than the reconfiguration with an average BCR of 1.34. It would also necessitate a future replacement program when these replaced assets reach end of life. As a result, this option is not preferred.

4.4.3 Neutral Bonding

Under this option the neutral of the dedicated LV mains would be bonded to the neutral on the LV distributor. This would increase the unserved energy risk and reduce the public safety risk. Bonding the dedicated circuit to the neutral of the LV distributor would not address the growth in failures predicted across the population due to conductor failure and lead to an increase in realised outages on the LV network. Under this option the increased unserved energy would still support the reconfiguration of the mains at the cost of an additional site visit. In evaluating this option, the average BCR is positive, however, less effective than reconfiguration.

4.4.4 Reconfiguration

Under this option the dedicated LV mains can be retired, removing the ongoing outage and safety risks compared to the other options. This has increased effectiveness and is also lower cost than replacement. In evaluating this option, the average BCR is higher than the alternative options and therefore remains the preferred option.

5. Major Projects

5.1 Replace 132kV feeders and switchgear at Drummoyne Zone Substation

5.1.1 Background

The 132kV underground sub-transmission cables (Feeders) connecting Drummoyne Zone Substation (ZS) to the Rozelle Sub-transmission Substation (Feeder 202) and to the Mason Park Switching Station (Feeders 203 & 204) are oil filled cables totalling 11kms in circuit length. Additionally, the 132kV switchgear at Drummoyne ZS has known condition issues and requires replacement. Ausgrid has a strategy to retire this cable technology and replace this type of switchgear when the benefits of replacement outweigh the cost.

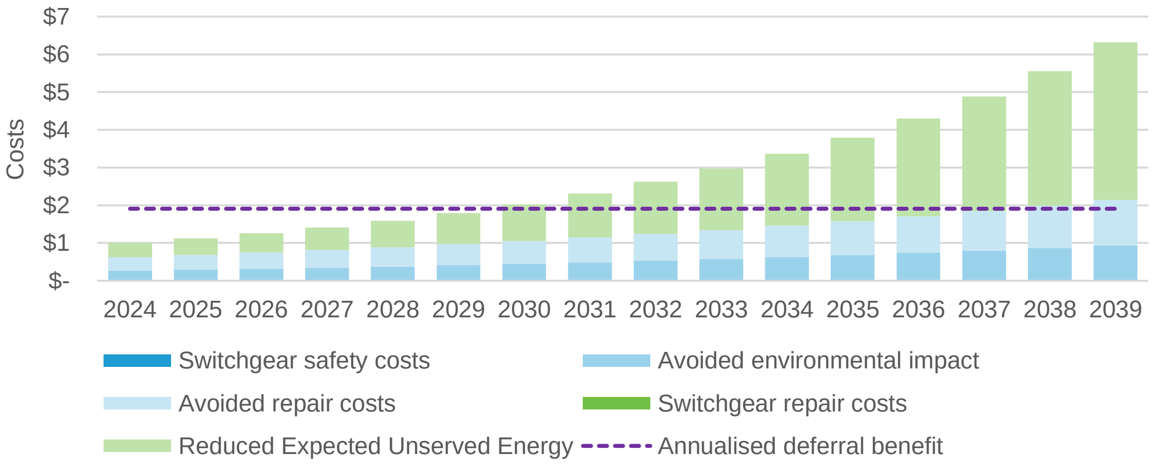
5.1.2 Project Need

Expected unserved energy (EUE), unplanned repairs and environmental risks (based on forecast failure rates and the history of oil leaks) are expected to increase to a level that supports replacement of the oil filled cables in the upcoming regulatory period. The 132kV switchgear at Drummoyne Zone is the last of its type on the Ausgrid network and has a history of SF6 gas leaks, condition issues and outages. Repairs have been undertaken utilising spare parts from out-of-service panels. Replacing the switchgear in conjunction with the oil filled cables reduces the need for rework and reduces the total cost to customers compared to undertaking these as separate projects.

5.1.3 What has changed with respect to our Initial Proposal

Since our Initial Proposal the forecast need for replacement has changed from FY31 to FY30 due to reduced cost estimates (driven by contracted delivery efficiencies for cable replacement works) and increased load growth leading to a higher EUE risk. In our Initial Proposal, the direct cost was estimated to be $93 million however, this estimate has been reduced to $88 million in our Revised Proposal. The advancement of the project by 1 year causes an increase of $7 million in expenditure required during the 2024-29 period as shown in **Figure 15**.

Figure 15. Cost Benefit Analysis - Replace 132kV feeders and switchgear at Drummoyne ZS (constant $m, FY22)



5.1.4 Scope for the preferred option

The replacement of these assets with modern equivalent technology remains the preferred option. The direct cost is $88 million, of which $83 million will be incurred in the 2024-29 period as shown in **Figure 16**. This represents a $7 million increase to the 2024-29 period compared to the Initial Proposal.

Figure 16. Project Cashflows – Replace 132kV feeders and switchgear at Drummoyne ZS (real $m, FY24)

	FY25	FY26	FY27	FY28	FY29	FY25-29 TOTAL	FY30-35
Feeder 202	0.2	1	6	8	2	18	**1**
Feeders 203 & 204	1	4	16	23	6	50	**3**
132kV switchgear	0.3	2	4	6	2	15	**1**
Total	**1**	**7**	**25**	**38**	**11**	**83**	**5**

5.2 Replace 33kV Feeders supplying Paddington Zone Substation

5.2.1 Background

The 33kV underground sub-transmission cables connecting Surry Hills Sub-transmission Substation with Paddington Zone Substation (Feeders 380, 381 and 382) are gas pressure cables commissioned in 1966 with a total circuit length of 4.5km. Ausgrid has a strategy to retire this cable technology when the benefits of replacement outweigh the cost.

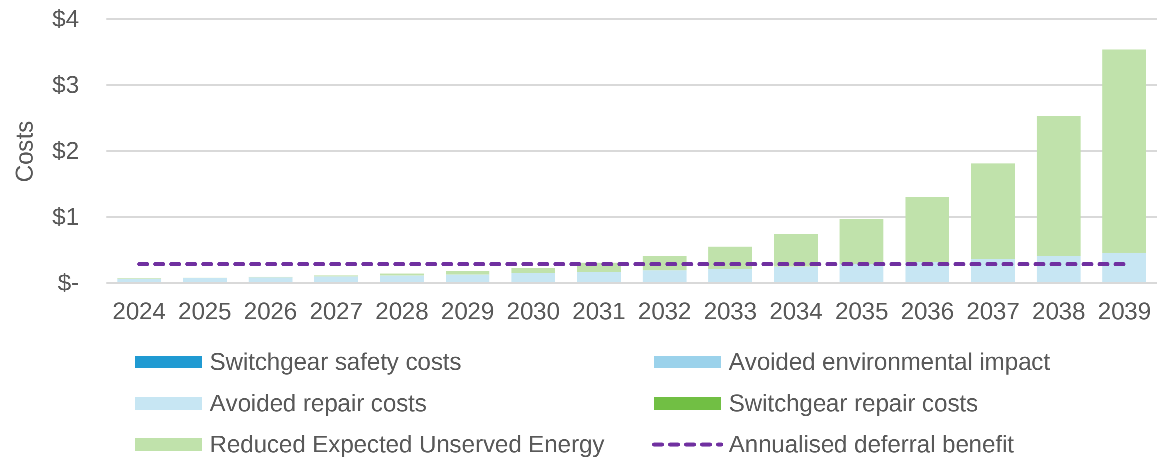
5.2.2 Project Need

In the event of a failure, gas pressure cables are difficult to repair and re-pressurise and can often lead to multiple failures on the same cable, extending restoration times and customer outage duration. The risk of EUE and unplanned repairs (based on predicted failure rates) is expected to increase to a level that supports prudent replacement activity commencing in the upcoming regulatory period.

5.2.3 What has changed with respect to our Initial Proposal

Previous modelling estimated the project would be cost-benefit positive in FY32 and was therefore not included in our Initial Proposal for the 2024-29 period. However, our latest load forecast has increased in this area, leading to an increase of 0.8 MWh in EUE, supporting the need for prudent replacement being brought forward to FY31. This results in the need to initiate enabling works during the 2024–29 period to meet the proposed date as per **Figure 17**.

Figure 17. Cost Benefit Analysis - Replace Paddington ZS 33kV feeders (constant $m, FY22)



5.2.4 Scope for the preferred option

The only credible option is to replace the feeders like-for-like, using modern equivalent technology, and retiring the existing gas pressure cables. The direct cost of these replacement works is $10 million, of which $6 million will be incurred during the 2024-29 period as per **Figure 18**.

Figure 18. Project Cashflows – Replace Paddington ZS 33kV feeders (real $m, FY24)

	FY25	FY26	FY27	FY28	FY29	FY25-29 TOTAL	FY30-35
Feeders 380, 381 & 382	**-**	**-**	**0.1**	**1**	**4**	**6**	**5**

5.3 Replace 33kV switchgear at Merewether Sub-transmission Substation

5.3.1 Background

Merewether 132/33kV Sub-transmission Substation (STS) located in the Newcastle area was commissioned in 1967 and supplies six 33/11kV Zone Substations. It is equipped with three 120MVA 132/33kV transformers and four sections of 33kV switchgear comprising twenty-four 33kV oil insulated circuit breakers. Ausgrid has a strategy to progressively replace 33kV oil insulated circuit breakers when the benefits of replacement outweigh the cost.

5.3.2 Project Need

The Merewether STS 33kV switchgear is a unique design with oil insulated circuit breakers installed inside a building. The failure of oil insulated circuit breakers and the associated wall bushings could:

- Initiate a building fire, or
- Result in damage to doors, walls and roof panels and compromise the structural integrity of the building.

Merewether STS will be the last sub-transmission substation with oil insulated circuit breakers.

Following detailed site and design review post our initial proposal the building itself was assessed as having:

- Flammable materials in the ceiling,
- Defective fire systems,
- Defective roller doors and asbestos throughout.

Due to the inherent issues with the design and the degrading condition of the building it is anticipated that the building will require replacement within 15 years.

5.3.3 What has changed with respect to our Initial Proposal

Our Initial Proposal included a $3 million allowance for the like-for-new in situ 33kV circuit breaker replacements consistent with our existing replacement program. During scoping of the circuit breaker replacements, the issues associated with the building as well as physical constraints due to the increased footprint of modern equivalent circuit breakers, requiring extensive civil works were identified which would require additional expenditure to enable replacement of the 33kV circuit breakers.

Since our Initial Proposal, the Merewether STS building condition and need for switchgear replacement has been re-evaluated. Based on predicted failure rates, the risk from unserved energy, safety and the cost of unplanned repairs are expected to increase to a level that supports the need for replacement, including the building, within the 2024-29 period.

Ausgrid has undertaken a detailed design review and testing of options for replacement of the switchgear and/or building under a range of scenarios and potential remaining lives. The scenarios that have been considered for the Merewether 132/33k STS site are:

- No revision to the Initial Proposal – assessed as not feasible due to emerging need, degrading risks, and benefits to replace the 33kV switchgear and associated equipment within the existing building.
- Like-for-new replacement of 33kV switchgear with a deferred replacement of the existing building.
- Rebuild to replace the 33kV switchgear and building at site.

The updated economic scenario analysis supports the greenfield replacement of the switchgear and building by FY30 as shown in **Figure 19** and has the highest NPV out of the scenarios.

Figure 19. Cost Benefit Analysis – Greenfield replacement of Merewether STS 33kV switchgear (constant $m, FY22)

While the cost to proactively replace switchgear is higher in the 2024-29 regulatory period compared to the cost of progressively replacing the 33kV circuit breakers, the benefits, including improved reliability and reduced maintenance, were found to outweigh the increase in cost. As a result, maintaining the option as per the Initial Proposal was assessed as not feasible due to the existing needs and benefits to replace the 33kV switchgear.

The switchgear only replacement scenario is not preferred due to the known condition issues and associated replacement benefits. Concurrent replacement of the Merewether STS switchgear and building through a singular project was also found to be cost-effective, practical and efficient. The integration of modern switchgear equipment within a new building will also optimise performance and safety of the system.

As a result of this analysis the replacement of the existing 33kV circuit breakers has been removed from the 33kV bulk oil switchgear program and updated with the full replacement cost for the switchgear and the building.

5.3.4 Scope for the preferred option

The proposed solution involves the construction of a new building to house the new 33kV switchgear and retirement of the aged 33kV switchgear. The direct cost is estimated to be $24 million, all of which is expected to be incurred in the 2024-29 period as per **Figure 20**. As shown in **Figure 20**, to avoid double counting, the expenditure previously included for replacement of the 33kV circuit breakers ($3 million) in situ has been removed from the repex forecast.

This has been partially offset by reducing the expenditure in the 33kV bulk oil switchgear program.

Figure 20. Project Cashflows – Replace Merewether STS 33kV switchgear (real $m, FY24)

	FY25	FY26	FY27	FY28	FY29	FY25-29 TOTAL	FY30-35
Merewether 33kV switchgear	0.2	3	8	8	4	24	**0**
33kV bulk oil switchgear program	0	0	0	0	0	0	**0**