5.14.1

Project justifications for 11kV switchgear replacements

Ausgrid

Content

1 INTRODUCTION

1.1 What is the purpose of this document

This document provides a summary of the need, options, timing and costs for each of the 11kV switchgear replacement projects that we have identified in our proposed standard control services (SCS) capital expenditure (capex) for the 2019-24 regulatory period.

The purpose is to provide the AER, its consultants and our stakeholders with a high level view of the need for individual 11kV switchgear projects, and to show that our analysis of timing, options and cost estimates is efficient and prudent, as required by the National Electricity Rules (the Rules).

1.2 Where does this document fit with other material in our Regulatory Proposal?

The underlying strategy and planning context for developing the 11kV switchgear replacement program has been described in Attachment 5.01 (Ausgrid's proposed capital expenditure). This information is critical to understanding how Ausgrid has developed its 11kV switchgear program within the context of its total forecast capex. The key elements of Attachment 5.01 that should be read alongside this document include:

- Section 2 which explains the capital planning process
- Section 3 which explains how our total capex meets the requirements of clause 6.5.7 of the Rules
- Section 4 which explains Ausgrid's total replacement program, including an overall description of the sub-transmission cable replacement program.

Attachment 5.01 also identifies a list of supporting attachments where further information on our capital planning process, key inputs and results of the AER's replacement expenditure (repex) model can be found.

1.3 Structure and contents

This document provides a list of significant 11kV switchgear projects where we forecast to incur a capital cost in the 2019-24 regulatory period. We then provide a description of each of these projects including identifying the need, options, timing and costs. Underpinning documentation, including methodologies, area plans, cost benefit analysis and planning studies, is available on request.

2 PORTFOLIO OF PROJECTS

Table 1 below identifies the most significant 11kV switchgear replacement projects where we expect to incur forecast SCS capex in the 2019-24 regulatory period. The table provides the name of the project, expected start and end date, and the forecast SCS capex in the 2019-24 period.

Table 1. Project list for 11kV switchgear replacement program

Project name	Cost ($m, real FY19)		Project start date	Project end date
	2019-24	Total		
1. Mascot (before DM)	48.8	49.1	2019	2025
Mascot* (after DM)	21.9	51.2	2021	2027
2. Concord (before DM)	21.0	23.6	2018	2022
Concord* (after DM)	20.8	22.4	2021	2025
3. Enfield	17.2	30.8	2017	2022
4. City East	15.6	37.3	2017	2023
5. Dalley Street	14.6	24.1	2017	2025
6. Clovelly	12.9	13.5	2021	2025
7. Miranda	11.2	12.5	2021	2025
8. Tarro	8.0	9.9	2018	2022
9. Surry Hills	5.7	13.6	2018	2021
10. Botany	5.3	5.7	2022	2025
11. Lidcombe (Groups 1 & 2) (before DM)	5.0	22.8	2017	2029
Lidcombe (Groups 1* & 2) (after DM)	5.0	24.3	2017	2032
12. Flemington	4.4	6.2	2018	2021
13. Stockton	4.4	5.5	2018	2022
14. Denman	3.6	4.0	2017	2021
15. Darlinghurst	3.3	17.3	2018	2031
16. Riverwood	2.1	10.0	2023	2027
17. Milperra	1.3	9.1	2023	2027
18. Pymble	1.2	12.0	2023	2028
19. Leightonfield (before DM)	3.0	7.9	2022	2027
Leightonfield* (after DM)	0	8.4	2025	2030
20. St Ives (before DM)	1.3	14.6	2023	2027
St Ives* (after DM)	0	15.7	2026	2030

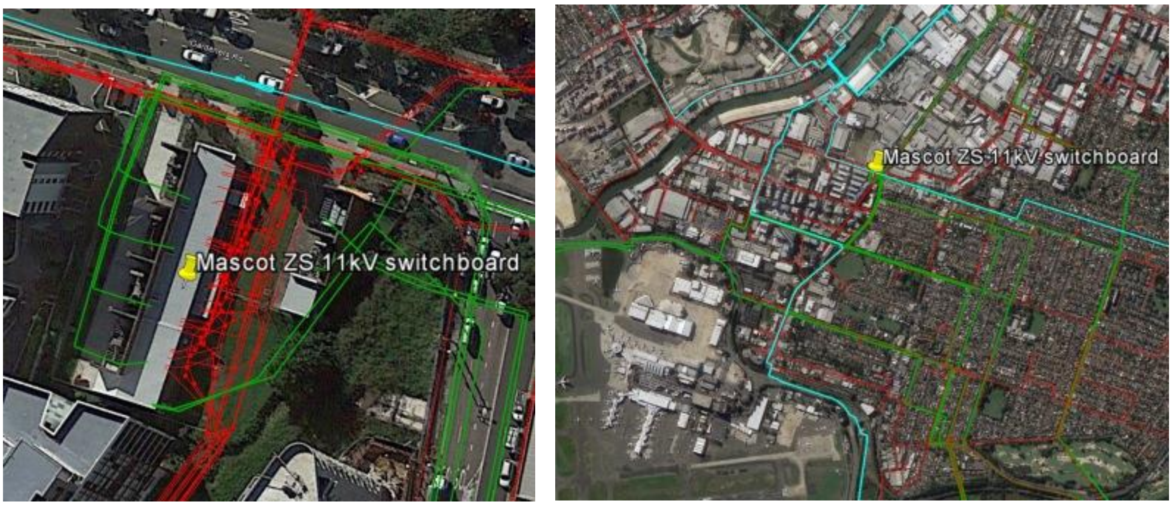
*These projects are part of a targeted demand management (DM) program consisting of six significant projects associated with the replacement/retirement of aged assets. Consistent with customer feedback, our opex forecast includes expenditure to further develop our demand management capabilities in the face of uncertainty over future technologies and energy demand and consumption patterns. We are proceeding with these projects, where the benefits of implementing a demand management solution (i.e. the benefits from deferring replacement capex) outweigh its costs. The solution will help us defer investments related to the replacement or retirement of aged assets and offer customers incentives to invest in energy efficiency solutions that will lower their energy use and their bills.

3 PROJECT 1 - MASCOT

3.1 Project description

The driver for this project is the condition of the existing 11kV switchgear at the Mascot 33/11kV Zone Substation in the Eastern Sydney region of Ausgrid's network. The compound and air insulated switchgear, which includes oil-filled circuit breakers, is nearing the end of its life. The assessment of options took account of the fact that the six 33kV underground cables that supply Mascot from Bunnerong North Subtransmission Substation (STS) are also near the end of their lives, meaning that the entire Zone Substation and its source of supply needed to be considered together. The optimal solution is to replace the substation with a new 132/11kV Substation located on a nearby green field site, and to take supply at 132kV from 132kV cables that pass nearby. The total project cost is $51.1 million, of which $45.5 million is attributable to the replacement of the switchgear, and the remainder, $5.6 million, is attributable to the replacement of the cables.

Figure 1. Mascot Zone Substation



3.2 Need

Mascot is a 33/11kV Zone Substation, and is supplied by six 33kV cables from Bunnerong North STS. These six cables are directly connected to six 33/11kV transformers. Mascot Zone Substation was commissioned in 1946.

Mascot zone contains three types of 11kV switchboards with different manufacturers and technologies, and condition issues have been identified for each of these. The air insulated and compound insulated switchgear, which all include oil-filled circuit breakers, is nearing the end of its life. The oldest switchboards are compound insulated and will be more than 70 years old in 2019. The condition assessment, which included electrical tests, concluded that this switchgear should be replaced within five to 10 years. The air insulated switchboards would be more than 50 years old and incorporate oil circuit breakers that pose operational and safety risks.

The main consideration driving the replacement of the 11kV switchboard at Mascot zone is its expected contribution to unserved energy.

3.3 Options

We examined the following options as part of Ausgrid's planning process:

1. Replace the Mascot 11kV switchgear on the same site with an equivalent modern design, while also replacing the existing 33kV cable supply from Bunnerong North STS with 33kV cables from a closer source (Alexandria STS).
2. Replace the Mascot 11kV switchgear on the same site with an equivalent modern design, while taking supply at 132kV instead of 33kV.
3. Establish a replacement 132/11kV zone substation on an alternative site, and reconnect 11kV feeders to this site.
4. Transfer of all 11kV load from Mascot to adjacent zones and decommission Mascot.
5. Consideration of demand management

There is insufficient capacity in adjacent zones to accept load transfer from Mascot on a permanent basis, so Option 4 is not feasible.

Options are constrained by the fact that Mascot has developed into a high density residential, commercial and light industrial suburb since the establishment of the underground railway that serves the airport. The existing zone substation site is now surrounded by high-rise developments, and there is limited space in roadways for additional cables. Further there is insufficient space on the site to accommodate replacement of 11kV switchgear, 33kV cables and to replace the existing 33/11kV transformers that are also in poor condition, while maintaining reliable supply. Options 1 and 2 involve significant timing and technical risk.

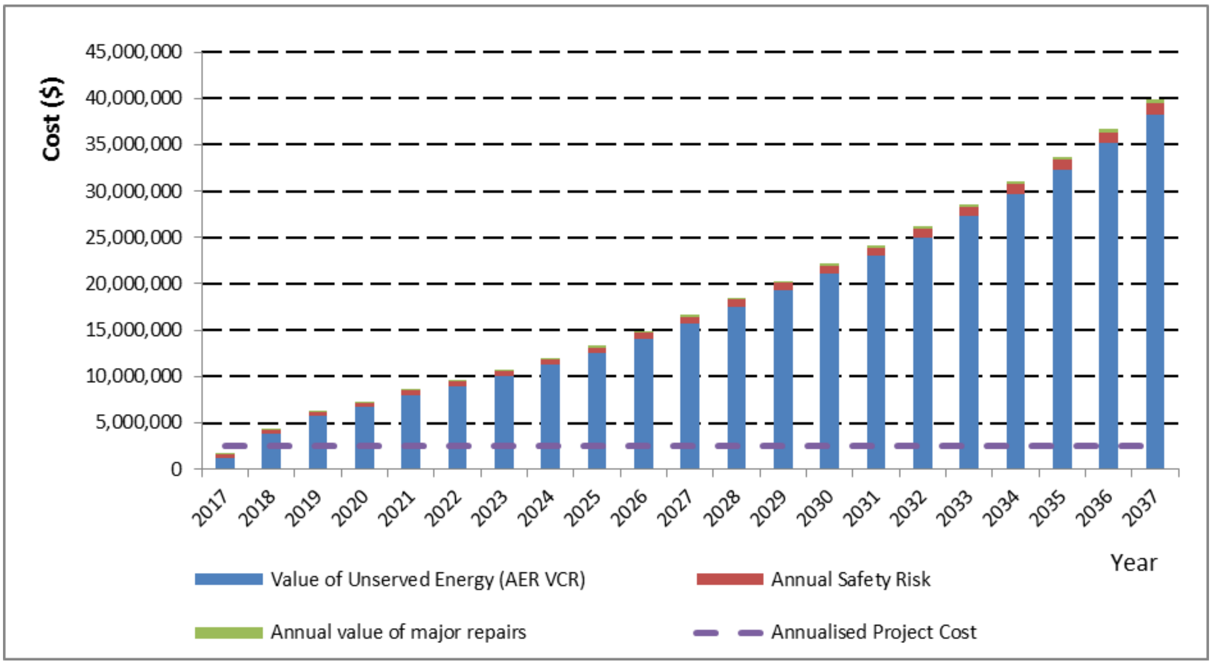
The preferred network option is therefore to establish a replacement 132/11kV zone substation on a nearby greenfield site with modern equivalent switchgear (Option 3).

This option is also consistent with minimising the cost of replacing the six 33kV cables that presently supply Mascot zone from Bunnerong North STS, and the cost of replacing oil-filled 132kV cables that serve the Eastern Suburbs.

3.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to blackouts attributable to all the assets to be replaced, to identify a break-even replacement date of 2018 as illustrated in the cost and benefit graph below. This is earlier than suggested considering switchgear condition only.

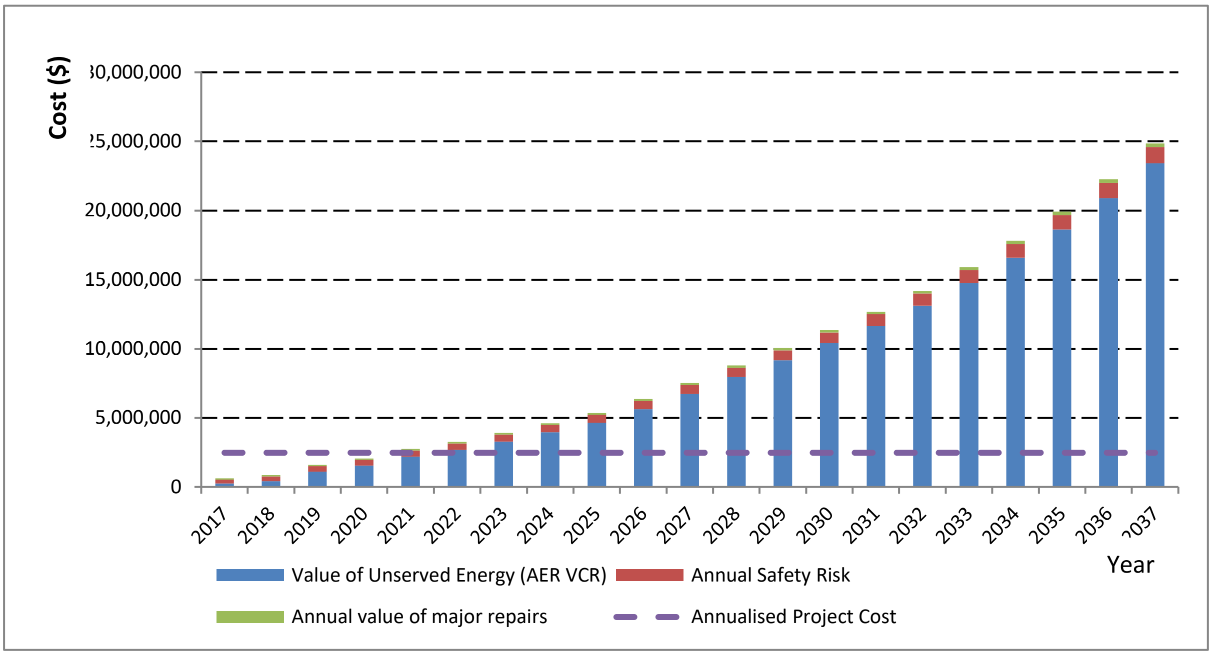
Figure 2. Total risk versus project deferral benefit



This timing is also driven by the need to coordinate the work with the replacement of other assets as described in Attachment 5.14 while maintaining the required levels of reliability to customers. In addition, deliverability, resource availability, cash flow smoothing and demand management initiatives are other factors that define the optimum timing to initiate the project. In consideration of these factors, the load at risk at Mascot in the short term will be mitigated as part of a committed project by transferring 25MVA load from Mascot to Green Square Zone Substation by 2018.

The cost benefit analysis results after the 11kV load transfer to Green Square Zone Substation indicates a break even date of 2021. Based on deliverability and resource availability, the optimum delivery date of the preferred network solution is 2022/23.

Figure 3. Total risk versus project deferral benefit (after load transfers to Green Square)



3.5 Demand Management

An analysis of non-network options considered how demand management could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative.

The cost benefit assessment has shown that the non-network option is able to efficiently reduce the estimated unserved energy at risk in advance of the completion date and a deferral of the preferred network option by three years from 2023 to 2026. As such, this option is the preferred option. Details on the capital and operating expenditure impacts are found in Chapter 5 (Capital expenditure) and Chapter 6 (Operating expenditure) of the regulatory proposal.

Note that at this early stage there is little or no specific information known about actual non-network options available in the area, so assumptions are made about the likely scale of demand reductions possible and estimated costs. These assumptions are based upon previous experience with delivery of demand management projects, submissions to non-network options reports from non-network solutions providers and lessons learned from demand management trials by Ausgrid and others.

As part of the Rules requirements, a Regulatory Investment Test for Distribution (RIT-D) will be conducted on this project, and a Non-Network Options Report (NNOR) will be published as part of the demand management engagement process. This will inform interested parties of the opportunity identified, and invite submissions from non-network proponents. Where the RIT-D process or any consequent tender for non-network solutions indicates that a modified non-network scope of work offers an improved cost benefit outcome, the selected solution to the need will be modified accordingly.

We forecast that construction work for the preferred option (including demand management) will start in 2021/22 for completion by 2026/27.

3.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the Business Planning and Consolidation (BPC) tool outlined in Attachment 5.03.

The cash flow for the project, including both the network option and the preferred option including demand management, are outlined in the table below.

Table 2. Project cash flow ($m, real FY19)

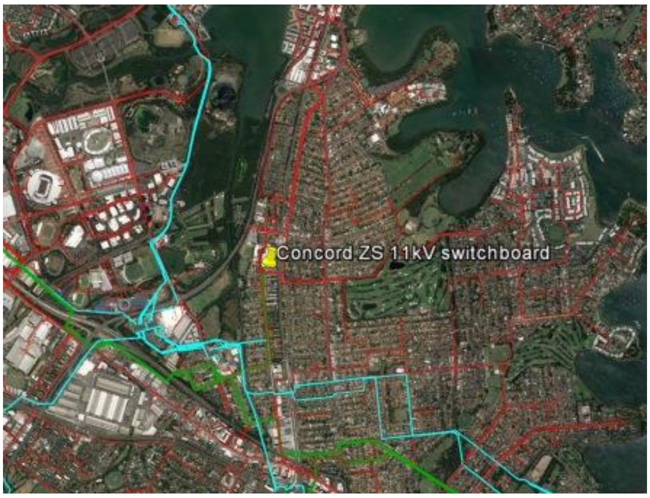
	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network Option	0.1	1.4	2.3	17.4	21.3	6.4	0.2
DM Option (preferred)	0.0	0.0	0.1	1.4	2.4	18.0	29.3

4 PROJECT 2 - CONCORD

4.1 Project description

The driver for the project is the condition of the existing 11kV switchgear at the Concord 33/11kV Zone Substation, which is located in the Sydney Inner West Area of Ausgrid's network. The 11kV switchgear is compound insulated, 62 years of age, and is nearing the end of its life. The preferred network solution is that the switchgear is replaced with modern equivalent switchgear with control and protection equipment in a new switchroom building within the existing site. The total project cost for such a solution is $22.4 million, of which $20.8 million is forecast to be incurred in the 2019-24 period.

Figure 4. Concord Zone Substation



4.2 Need

Concord Zone Substation was commissioned in 1955 and is supplied via four 33kV cables from Homebush Subtransmission Substation. These are predominantly cross-linked polyethylene (XLPE) type with small sections of paper/lead technology (HSL) type near the substation. The HSL cables are 62 years of age, but at present there are no known condition issues with these cables.

Concord Zone Substation comprises three groups of 11kV double busbar compound insulated switchgear. The existing 11kV circuit breakers comprise both oil and vacuum circuit breakers. A number of 11kV bulk oil circuit breakers (OCB) were assessed as having a remaining life of less than five years, and had recently been replaced with vacuum circuit breakers. Due to heightened fire risk, the remaining 11kV OCBs combined with the compound insulated switchgear technology can result in significant failures. The 11kV compound switchgear has been assessed as having a remaining life of five to 10 years based on Ausgrid's asset prioritisation process.

4.3 Options

We examined the following options as part of Ausgrid's planning process:

1. Replacement, which would involve the transfer of 11kV feeders from the old switchgear to the new switchgear in a new switchroom.

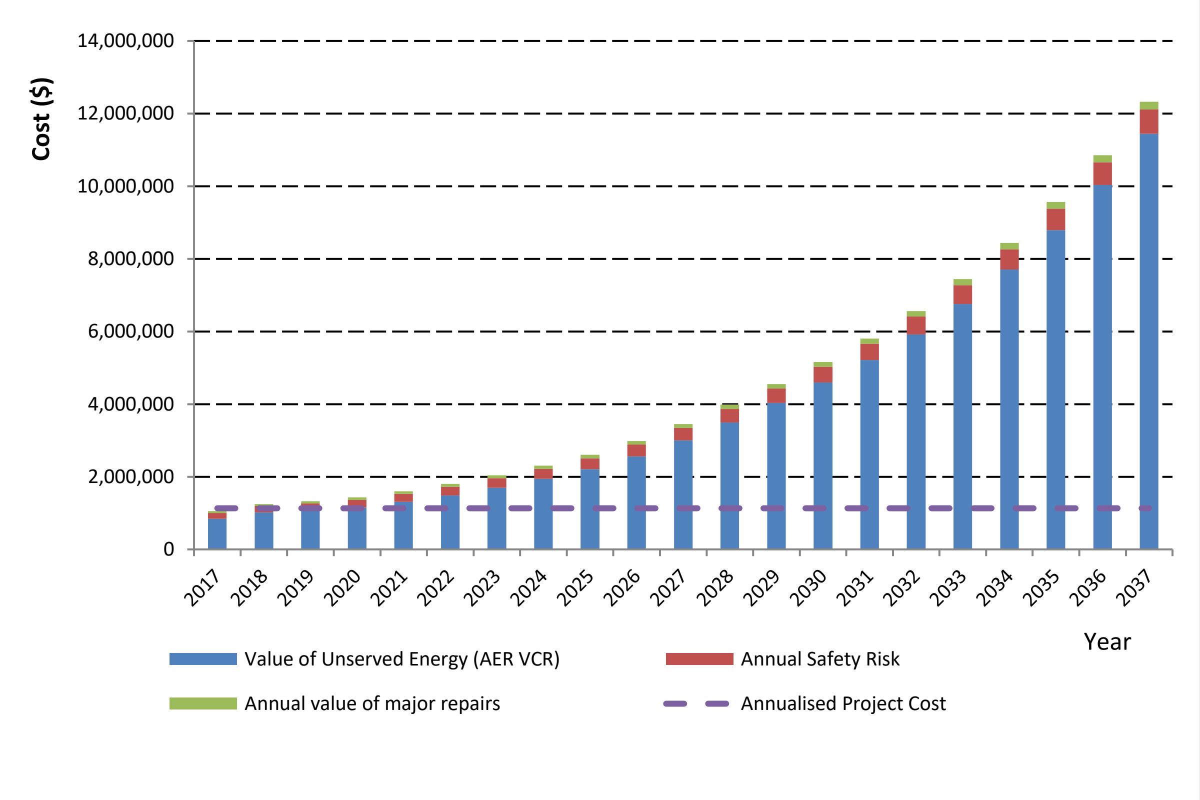
2. Construction of a new 33/11kV zone substation on a green field site to replace the existing Concord 33/11kV Zone Substation.
3. Construction of a new 132/11kV zone substation on a green field site to replace the existing Concord 33/11kV Zone Substation.
4. Consideration of demand management.

The preferred and most cost effective network solution is to replace the 11kV switchgear in a new switchroom, and in a staged manner within the current site (Option 1).

4.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date of 2018 as illustrated in the cost and benefit graph below. Based on deliverability and resource availability, the optimum delivery date for the preferred network solution is 2021.

Figure 5. Total risk cost versus project deferral benefit



4.5 Demand Management

An analysis of non-network options considered how demand management could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative.

The cost benefit assessment has shown that the non-network option is able to efficiently reduce the estimated unserved energy at risk in advance of the completion date and a deferral of the preferred network option by three years from 2021 to 2024. As such, this option is the preferred option. Details on the capital and operating expenditure impacts are found in Chapter 5 (Capital expenditure) and Chapter 6 (Operating expenditure) of the regulatory proposal.

Note that at this early stage there is little or no specific information known about actual non-network options available in the area, so assumptions are made about the likely scale of demand reductions possible and the estimated costs. These assumptions are based upon previous experience with delivery of demand management projects, submissions to non-network options reports from non-network solution providers and lessons learned from demand management trials by Ausgrid and others.

As part of the Rules requirements, a RIT-D will be conducted on this project, and a NNOR will be published as part of the demand management engagement process. This will inform interested parties of the opportunity identified, and invite submissions from non-network proponents. Where the RIT-D process or any consequent tender for non-network solutions indicates that a modified non-network scope of work offers an improved cost benefit outcome, the selected solution to the need will be modified accordingly.

We forecast that construction work for the preferred option (including demand management) will start in 2021/22 for completion by 2024/25.

4.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project, including both the network option and the preferred option including demand management, are outlined in the table below.

Table 3. Project cash flow ($m, real FY19)

	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network Option	2.6	10.3	9.2	1.5	-	-	-
DM Option (preferred)	-	-	0.1	1.1	5.8	13.8	1.6

5 PROJECT 3 - ENFIELD

5.1 Project description

The project is to retire and replace the existing 11kV switchgear at Enfield Zone Substation in the Canterbury Bankstown region of Ausgrid's network. The compound insulated switchgear is nearing the end of its life, and the gas-insulated 33kV cables that supply Enfield Zone from Canterbury Subtransmission Substation have also been prioritised for retirement.

Our options analysis has determined that the assets should be replaced with a new 132/11kV Strathfield South Zone Substation on a green field site and supplied at 132kV by looping in to 132kV overhead feeder 911 that passes nearby. Considering all these condition issues and based on our cost-benefit analysis the assets should all be replaced by 2021. Commitment to the project is expected in early 2018. The total project cost is $30.7 million, of which $27.7 million is attributable to the replacement of the switchgear, and the remainder, $3.0 million is attributable to the replacement of the cables. Expenditure of $17.1 million is expected to be required in the 2019-24 period.

Figure 6. Endfield Zone Substations

5.2 Need

The existing Enfield 33/11kV Zone Substation was commissioned in 1962 and is supplied by three 33kV gas pressure cables (feeders 639, 640 and 641) that originate from Canterbury Sub-Transmission Substation. The key requirement for this project is to enable the retirement of these 33kV gas pressure cables. Based on Ausgrid's "Strategic Asset Prioritisation Sub-transmission Cables" Report, feeder 640 is identified as having the highest leakage rate and second worst availability of all gas pressure cables. Feeder 641 has the tenth highest leakage rate and the worst availability. Feeder 639 is also among the lower performing feeders.

In early 2011, feeder 640 failed while feeder 639 was out of service for a gas leak repair. The next day, before feeder 639 could be returned to service, feeder 641 also failed. Over 7,200 customers were impacted and load shedding continued over the following four days, which coincided with a heatwave. Supply restoration involved deployment of 25 mobile generators and a temporary emergency 33/11kV substation connected to a Railcorp 33kV feeder. This incurred operational costs of $1.5 million, in addition to the value of customer load not supplied.

While a major underlying contributory factor was later found to be poor thermal resistivity of the backfill material at the fault location, the incident serves to demonstrate the heightened supply risk arising from the long repair times of gas pressure cables that are in poor condition.

Enfield Zone Substation comprises two groups of double busbar compound insulated 11kV switchgear with vacuum circuit breakers. There are other secondary issues at Enfield which need replacement such as 33kV control and protection which are mechanical type which are obsolete and spare parts are no longer available.

The main consideration driving the retirement of the 11kV switchgear and 33kV feeders at Enfield zone is its expected contribution to unserved energy.

5.3 Options

We examined the following options as part of Ausgrid's planning process:

1. Construction of new 132/11kV zone substation ("Strathfield South") on an Ausgrid-owned block of land to replace the existing Enfield 33/11kV Zone Substation.
2. Refurbishment of Enfield Zone Substation and replacement of the 33kV cable feeders from Canterbury STS.
3. Replacement of both Enfield and Dulwich Hill Zone Substations with a new 132/11kV zone substation.
4. Consideration of demand management.

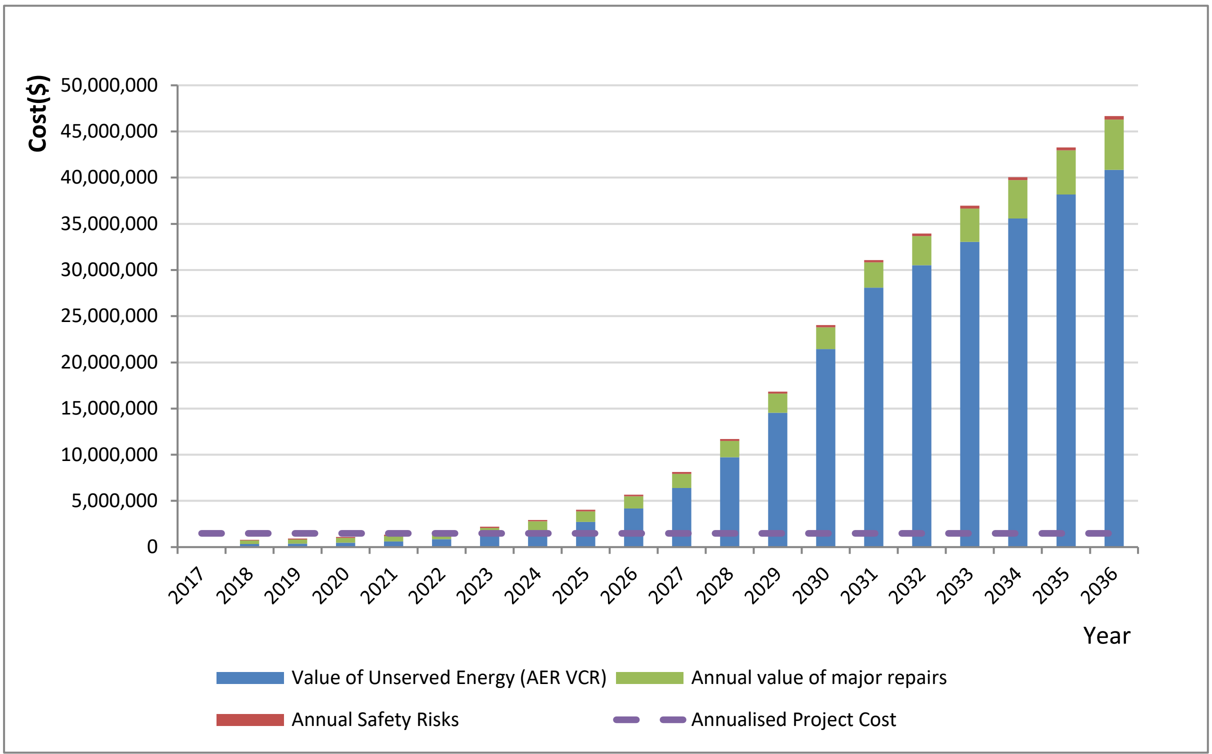
The preferred and most cost effective network solution to resolve issues at Enfield Zone Substation was determined to be to construct a new Strathfield South 132/11kV Zone Substation on an Ausgrid-owned block of land by connecting to a double circuit 132kV overhead feeder that traverses the area (Option 1).

This solution also contributes to addressing asset condition issues and possible capacity issues at Campsie Zone Substation when the 11kV switchgear at Campsie Zone Substation is replaced in the future.

5.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date. Based on Enfield 11kV switchgear only, the break-even replacement date is 2035. However, the main contribution to the unserved energy is the unreliable 33kV gas feeders. Combining the unserved energy contribution from 33kV feeders and 11kV switchgear, the break even need date to address the condition issues at Enfield zone is by 2022 as illustrated in the cost and benefit graph below.

Figure 7. Total risk versus project deferral benefit



Timing is driven by the need to coordinate the work with the replacement of the 33kV cables and other assets, while maintaining the required levels of reliability to customers. Deliverability, resource availability and cash flow smoothing define an optimum completion date of 2022. This requires commitment to the project in early 2018.

5.5 Demand Management

The condition of the 33kV feeders supplying Enfield Zone Substation, and the associated risk of failure is the principle driver for the proposed project, which will also result in the replacement of the 11kV switchgear. An analysis of non-network options considered how demand management could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative. The cost benefit assessment has shown that non-network alternatives were not found to be cost effective.

Note that at this early stage there is little or no specific information known about actual non-network options available in the area, so assumptions are made about the likely scale of demand reductions possible and the estimated costs. These assumptions are based upon previous experience with delivery of demand management projects, submissions to non-network options reports from non-network solution providers and lessons learned from demand management trials by Ausgrid and others.

As part of the Rules requirements, a RIT-D will be conducted on this project. If, during the consultation process, a non-network option is found to offer a cost effective alternative to the preferred network option, the selected solution to the need will be modified accordingly.

5.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project is outlined in the table below.

Table 4. Project cash flow ($m, real FY19)

	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network option	13.6	12.4	4.1	0.7	-	-	-

6 PROJECT 4 – CITY EAST

6.1 Project description

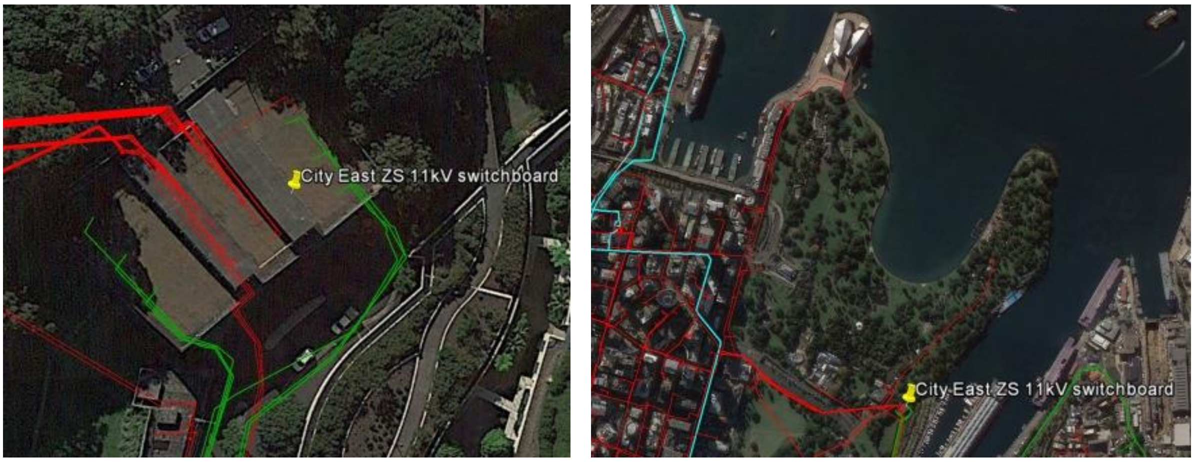
The driver for this project is the condition of the existing the 11kV switchgear and 33kV feeders at the City East 33/11kV Zone Substation, located near Woolloomooloo on the eastern border of the Sydney CBD region of Ausgrid's network. This project is committed, and construction will commence in the 2014-19 period.

The compound insulated switchgear that uses oil circuit breakers is nearing the end of its life. The switchboard is an orphan technology, not found elsewhere on the Ausgrid network. Failure of the equipment would cause lengthy blackouts that are incompatible with Ausgrid's Licence obligations. The planning analysis also considered the need to replace six 33kV HSL cables that supply City East from Surry Hills Subtransmission Substation that is located in the south of the CBD. Based on our cost-benefit analysis and consideration of associated projects the switchgear should be replaced by 2022/23.

The preferred solution is to progressively transfer the 11kV load currently supplied from City East to Belmore Park Zone Substation, which is located in the south of the CBD, near Central Station. This will require multiple 11kV cables to be laid from the Belmore Park service area to the vicinity of City East's service area. The plan also includes the decommissioning of City East Zone Substation and associated 33kV feeders and remediation of the site. The total project cost is $37.3 million, of which $15.6 million is forecast to be incurred in the 2019-24 period.

The preferred network strategy provides an optimum solution that also caters for the decommissioning of Dalley St Zone Substation, and associated 11kV load transfers from Dalley St to Belmore Park Zone Substation, as described in Project 5. This considers the installation of an extended 20-way duct bank in a common trench with sufficient capacity to transfer all load from both City East and Dalley St Zone Substations. Approximately $12 million of the total project cost is attributable to the decommissioning of Dalley St Zone Substation.

Figure 8. City East Zone Substation



6.2 Need

City East is a 33/11kV zone substation, and is supplied by six 33kV cables from Surry Hills 132/33kV Subtransmission Substation. These six cables are directly connected to six 33/11kV transformers. City East zone was commissioned in 1964.

The City East Zone Substation contains English Electric CV type compound insulated switchboard with oil filled circuit breakers. This is an orphan technology, not found elsewhere on the Ausgrid network. The switchgear and circuit breakers were given full insulation testing in 2014. These tests were to confirm the switchgear's insulation integrity and to observe the presence of tracking and electric discharge which are lead indicators for catastrophic failure. The results supported early replacement.

As this switchboard is an orphan, in the event of a catastrophic failure there are no available spares to undertake replacement. Recovery timeframes would depend on the ability to shift load to another zone substation. Depending on the severity of the damage to the switchboard, this might leave the substation abnormally switched for an extended period.

The existing oil containment system at City East Zone Substation is not adequate to contain the transformer oil, in the event of a transformer or bushing failure. In the event of failure, the deluge will overflow the containment system if in operation for more than 15-20 minutes. Under this scenario, Ausgrid would be reliant on Emergency Services to prevent or mitigate spills into Sydney Harbour. If the substation was to remain in service, upgrades would be required to allow the containment of oil and deluge water to prevent the spread of fire, oil spills and environmental damage.

The 33kV feeder cables supplying City East Zone Substation are paper/lead technology. While these cables were commissioned in 1946 (currently 71 years old) there is evidence that some sections may be older, being laid around 1930 (currently 87 years old). As expected, the cables which are older have a higher failure rate and are predominantly those on which recent failures have occurred.

6.3 Options

We examined the following options as part of Ausgrid's planning process:

1. Refurbishment of the existing zone substation, which would involve temporarily offloading City East load to an adjacent zone substation, and replacement of the 33kV cables.
2. Construction of a new zone substation at another location and retirement of the existing substation, after the load is transferred to the newly constructed substation.
3. Retirement of the existing substation and 33kV cables, with load transferred to other substations with available capacity.
4. Consideration of demand management.

As there are similar condition issues at Dalley St Zone Substation, the area planning process reviews both these issues together, to find a preferred strategy that resolves all the individual issues. The following strategies are analysed in the area planning review:

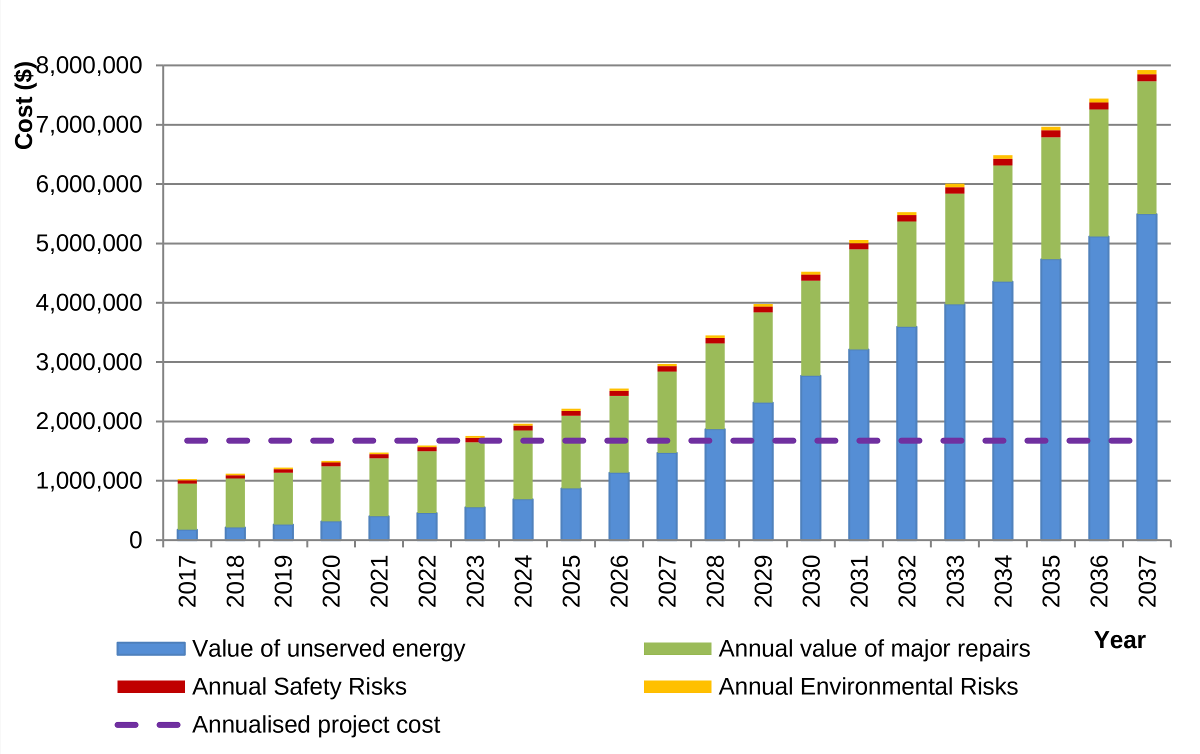
1. New Bligh St 132/11kV Zone Substation to decommission both Dalley St and City East Zone Substations.
2. Retire Dalley St and City East Zone Substations by transferring load to City North and Belmore Park zone substations.
3. Refurbish City East and retire Dalley St Zone Substation.

The preferred and most cost effective network strategy is Strategy 2 – Retire Dalley St and City East zone Substation by transferring load to City North and Belmore Park. A subsequent cost benefit analysis using risk quantification techniques confirmed this to be the preferred network strategy.

6.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date of 2022/23 as illustrated in the graph below.

Figure 9. Total risk cost versus project deferral benefit



This timing is also driven by the need to coordinate the work with the replacement of other assets as described in Attachment 5.14 while maintaining the required levels of reliability to customers. In consideration of these factors, the optimum timing to complete this project is recommended as 2022.

Construction work started in 2017 and is forecast to end in 2022.

6.5 Demand Management

We conducted a demand management assessment which showed that non-network alternatives cannot cost effectively address the risk of unserved energy from multiple, coincident failures leading to a total loss of connectivity. On this basis, it is not considered that demand management can contribute in any material way to the need or the timing of the project.

As part of the Rules requirements, a RIT-D will be conducted on this project. If, during the course of this process, a non-network option is found to offer a cost effective alternative to the preferred network option, the selected solution to the need will be modified accordingly.

6.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The project is essentially divided into two components. They are:

1. Transfer all loads from City East to Belmore Park Zone Substation, requiring work within the 11kV CBD distribution network.
2. Decommission City East Zone Substation and associated 33kV feeders and remediate the site.

The cash flow for the project is outlined in the table below.

Table 5. Project cash flow ($m, real FY19)

	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network option	21.7	4.8	7.5	3.3	-	-	-

7 PROJECT 5 – DALLEY ST

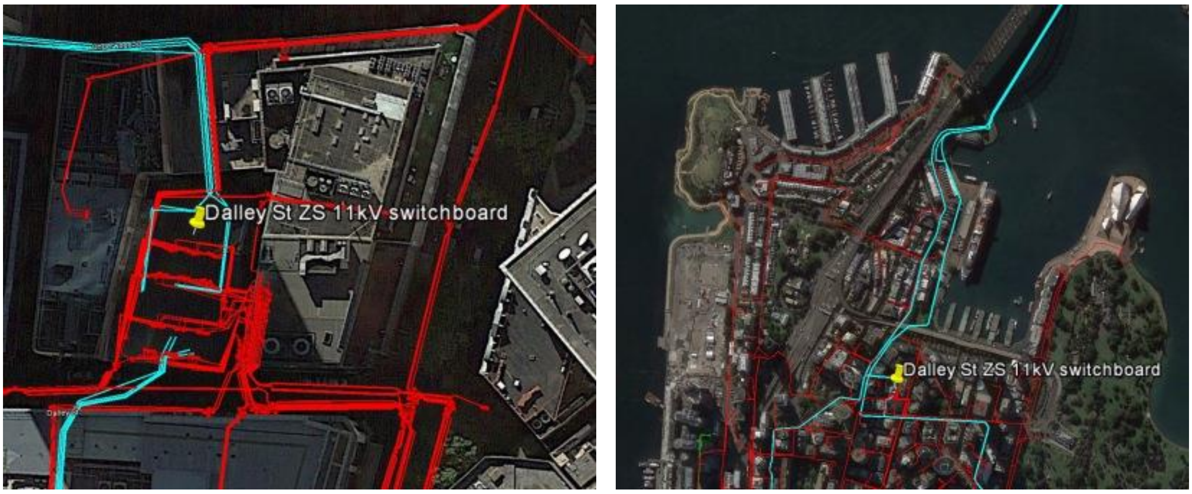
7.1 Project description

The driver for this project is condition of the existing 11kV switchgear at the Dalley St 132/11kV Zone Substation and its associated 132kV oil filled feeders, located near Circular Quay in the north of the Sydney CBD region of Ausgrid's network.

The compound insulated switchgear is nearing the end of its life, and has been assessed as requiring urgent retirement. The air insulated switchgear is in better condition than the compound switchgear but still needs to be addressed in the 2019-2024 period. The planning analysis also considered the need to replace four 132kV oil filled cables that supply Dalley Street zone from Surry Hills Subtransmission Substation that is located in the south of the CBD.

The preferred solution is to decommission the entire zone Substation, by progressively transferring the 11kV load currently supplied from Dalley St to Belmore Park and City North Zone Substation, which are both located in the CBD. This will require multiple 11kV cables to be laid to the vicinity of Dalley St zone. The plan also includes the decommissioning of Dalley St Zone Substation and remediation of the site. Based on our cost-benefit analysis and consideration of associated projects the switchgear should be replaced by 2023/24. The work will proceed in stages, and having regard for the complexity of the project, a target date of 2025 has been set for final decommissioning. The total project cost is $24.1 million, of which $14.7 million is forecast to be incurred in the 2019-24 period.

Figure 10. Dalley Street Zone Substation



7.2 Need

Dalley St is a CBD type 132/11kV zone substation, and is supplied by four 132kV oil filled cables from Surry Hills STS and Lane Cove STS. Dalley St Zone Substation was commissioned in 1969.

Dalley St Zone Substation comprises both compound-insulated Email HQ type switchgear and air-insulated Reyrolle LMT type 11kV switchgear. There are condition issues with the 11kV switchgear that varies in age, being up to 52 years. The Email HQ switchgear is single busbar type, with compound insulation. There are oil-filled current transformer (CT) chambers and voltage transformers (VT) on the transformer incomer panels. There have been several occasions when the CT chambers have leaked over recent years, which have required the removal of the CT chambers for repairs. Ausgrid has experienced an explosive failure of this type of switchgear. A flashover in the endbox of a panel at Dulwich Hill Zone Substation resulted in an explosive failure that compromised the structural integrity of the building.

As part of a risk mitigation strategy at Dalley St Zone Substation, an emergency group of 11kV switchgear was installed in a separate room to provide recovery should a similar failure occur at Dalley St Zone Substation. This does not provide a complete solution, because of the time required to transfer feeders.

The 132kV feeders entering and exiting Dalley St Zone Substation are oil filled cables and have a significant risk of oil leakage. The cables between Lane Cove STSS and Dalley St Zone Substation are planned to be retired. Also, the 132kV gas insulated switchgear and 132kV circuit switches have been determined to be approaching the end of their serviceable life. The other assets such as 132kV transformer bushings, control and protection equipment and the substation building have also been identified as being in an unacceptable condition. Consequently the decision has been made to retire the entire Dalley St Zone Substation.

7.3 Options

We examined the following options as part of Ausgrid's planning process:

1. Replacement of Dalley St Zone Substation with a new Bligh St 132/11kV Zone Substation.
2. Retirement of Dalley St Zone Substation and transfer of the load to other zone substations with sufficient capacity.
3. Refurbishment of existing Dalley St Zone Substation.
4. Consideration of demand management.

As there are similar condition issues at City East Zone Substation, the area planning process reviews both these issues together, to find a preferred strategy that resolves all the individual issues. The following strategies are analysed in the area planning review:

1. New Bligh St 132/11kV Zone Substation to decommission Dalley St and City East Zone Substations.
2. Retire Dalley St and City East Zone Substations by transferring load to City North and Belmore Park.
3. Refurbish City East and retire Dalley St.

Transferring load to City North and Belmore Park Zone Substations to enable the full retirement of both Dalley St and City East Zone Substations (Strategy 2) is the most cost effective means of addressing the key needs.

7.4 Timing

The issues at Dalley St zone will be addressed in two stages:

- Stage 1 – Load transfer from Dalley St to City North Zone Substation
- Stage 2 – Transfer remaining loads to Belmore Park zone and decommission Dalley St zone.

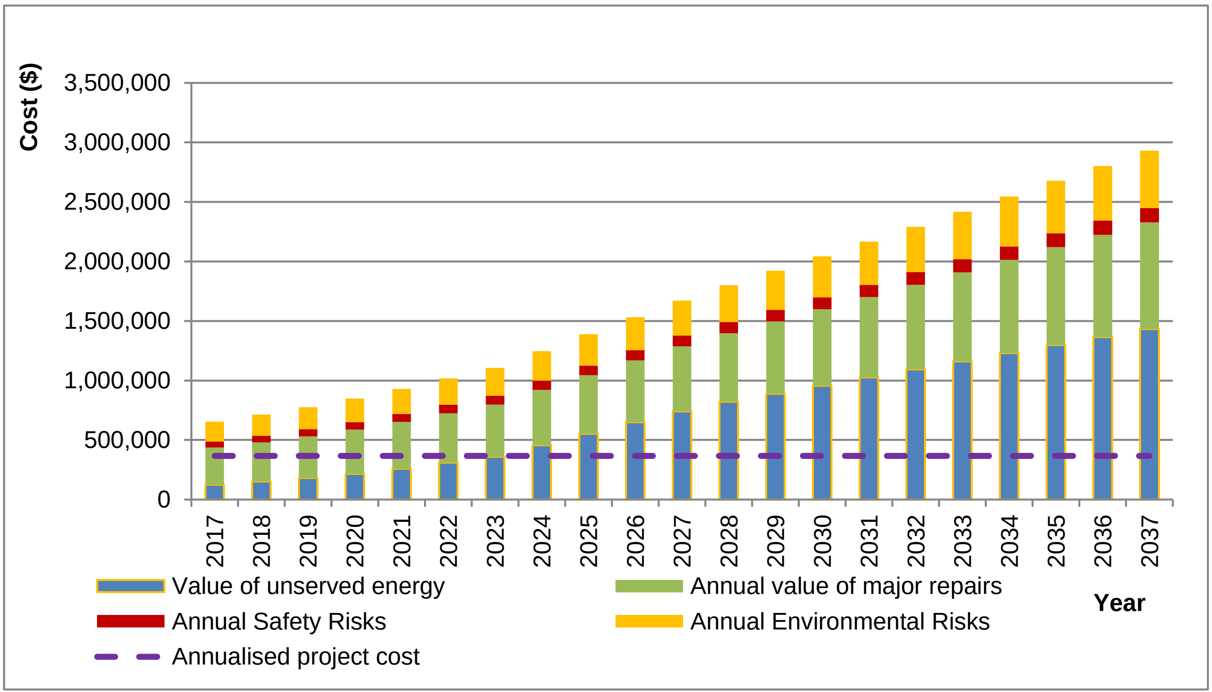
The load transfers to City North Zone Substation under Stage 1 are already committed and expected to be completed in 2018/19.

To achieve a cost effective strategy in the Sydney CBD area, an integrated approach for both City East and Dalley St Zone Substations are being considered which includes installation of an extended 20-way duct bank in a common trench with sufficient capacity to transfer all load from both City East and Dalley St Zone Substations as part of Project 4. Approximately $12 million of the total project cost in Project 4 is attributable to the decommissioning of Dalley St.

The project cost used in the cost benefit analysis is only the cost to do the load transfer from Dalley St to Belmore Park Zone Substation as the cost for the duct installation is already included as part of Project 4 (City East) . The optimum timing recommended is by 2022 to install the ducts.

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date to be at the earliest as illustrated in the graph below. Since the load transfer to Belmore Park Zone Substation and ultimate decommissioning of Dalley St Zone Substation can only be done after the installation of ducts (by 2022) as part of Project 4, the recommended replacement date for Dalley St Zone load transfer is by 2023/24 for Stage 2.

Figure 11. Total risk cost versus project deferral benefit



This timing is also driven by the need to coordinate the work with the replacement of other assets as described in Attachment 5.14 while maintaining the required levels of reliability to customers. The first transfer of load to City North began in 2017 and all decommissioning is to be completed by 2025.

7.5 Demand Management

We conducted a demand management assessment which showed that non-network alternatives cannot cost effectively address the risk of unserved energy from multiple, coincident failures leading to a total loss of connectivity. On this basis, it is not considered that demand management can contribute in any material way to the need or the timing of the project.

As part of the Rules requirements, a RIT-D will be conducted on this project. If during the course of this process a non-network option is found to offer a cost effective alternative to the preferred network option, the selected solution to the need will be modified accordingly.

7.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The project is essentially divided into two components. They are:

1. Transfer all loads from Dalley St to Belmore Park and City North Zone Substations, requiring substantial work within the 11kV CBD distribution network.
2. Decommission Dalley St Zone Substation and associated 132kV feeders and remediate the site.

The cash flow for the project is outlined in the table below.

Table 6. Project cash flows ($m, real FY19)

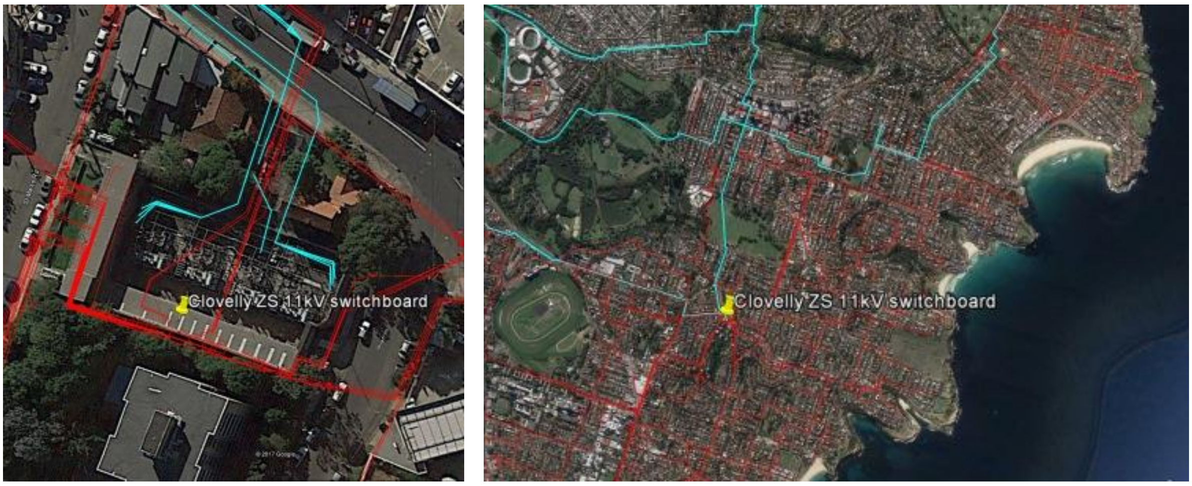
	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network Option	9.4	4.6	2.0	0.9	4.1	3.0	0.1

8 PROJECT 6 - CLOVELLY

8.1 Project description

The project is to retire and replace the existing air insulated 11kV switchgear (Group 2) at Clovelly Zone Substation in the Eastern Suburbs region of Ausgrid's network. The air insulated 11kV switchgear is nearing the end of its life. All the 132kV cables that supply Clovelly are oil filled and also require replacement because of their age and deteriorated condition. Both these condition issues have been considered when devising the replacement plan. Based on our cost-benefit analysis and other considerations the asset should be replaced by 2025. The total project cost is $13.5 million of which $12.9 million is forecast to be incurred in the 2019-24 period.

Figure 12. Clovelly Zone Substation



8.2 Need

Clovelly is a 132/11kV Zone Substation, and is supplied by two 132kV oil filled cables from Beaconsfield Bulk Supply Point (BSP) via Zetland zone and a 132kV feeder from Double Bay. Clovelly Zone Substation was commissioned in 1970.

Clovelly Zone Substation comprises both air and compound insulated 11kV switchgear which are aged around 47 years, and its poor condition has resulted in its prioritisation for retirement. As a result of this prioritisation in 2012, the compound-insulated 11kV switchgear at Clovelly Zone Substation (Group 1) was given the highest priority for retirement. A project is committed and is in progress to transfer the Group 1 load to adjacent zone substations (Kingsford and Waverley Zone Substations) and to decommission Group 1 switchgear and associated transformers. This stage is scheduled for completion in 2019.

The current need is to address the Group 2 11kV switchgear asset condition issues at Clovelly zone. The plan is to replace the existing switchgear in the space vacated by Group 1, and to transfer the Group 2 load to it. Completion is anticipated in September 2024.

Apart from the Clovelly Group 2 switchgear, there are number of other condition issues associated with assets in the Eastern Suburbs area that affect Clovelly, and these are all being addressed in other projects. These are:

1. Zetland zone substation 11kV switchgear.
2. 132kV oil filled feeders supplying Zetland and Mascot.
3. 132kV oil filled feeders supplying Kingsford and Maroubra.

4. Mascot zone substation 11kV switchgear and supplying 33kV feeders.

The need to address the issue of 11kV switchgear at Clovelly Zone Substation was considered in the context of all these issues, and is consistent with an overall strategic solution.

The main consideration driving the replacement of the 11kV switchboard at Clovelly zone is its expected contribution to unserved energy.

8.3 Options

We examined the following options for Clovelly 11kV Group 2 switchgear as part of Ausgrid's planning process:

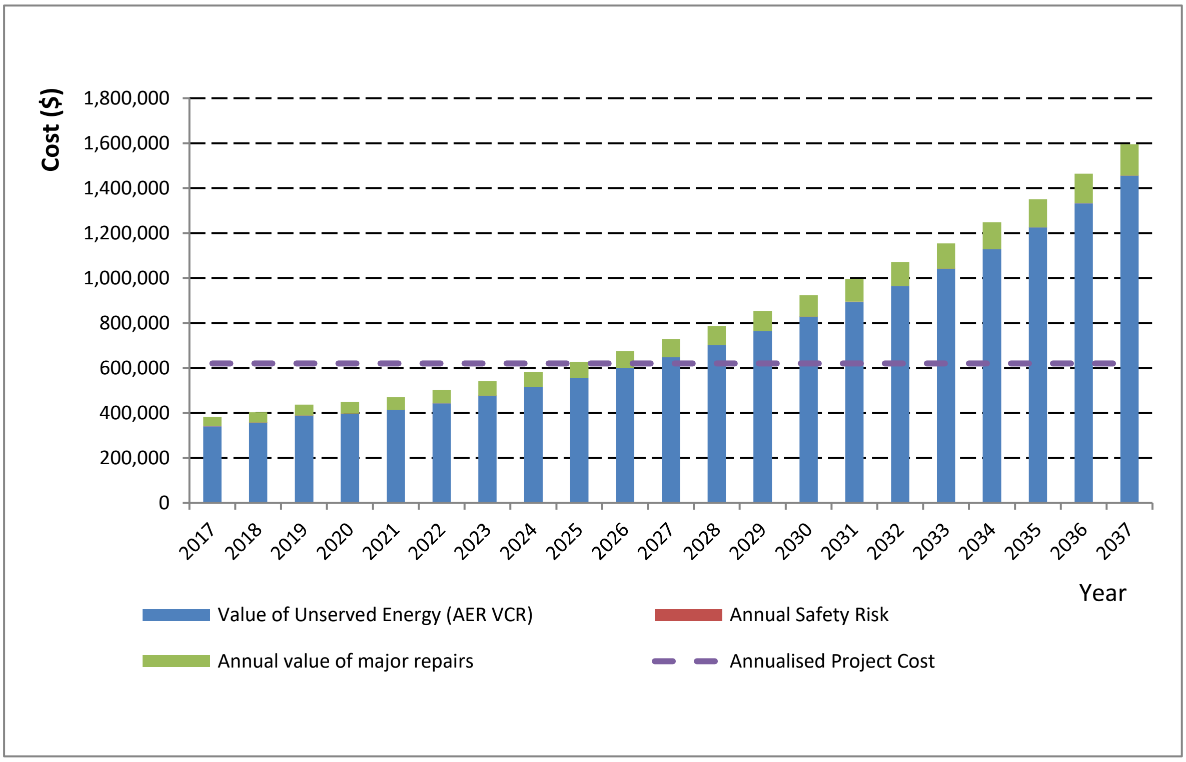
1. 11kV switchgear replacement on the same site in the space available after decommissioning Group 1 switchgear.
2. New Clovelly 132/11kV zone and retire the existing zone.
3. Retire Clovelly zone via 11kV load transfers to surrounding zones.
4. Consideration of demand management.

Option 1 is the preferred and most cost effective network solution.

8.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date of 2025 as illustrated in the cost and benefit graph below.

Figure 13. Total risk cost versus project deferral benefit



This timing is also driven by the need to coordinate the work with the replacement of the other assets as described above while maintaining the required levels of reliability to customers. Deliverability, resource availability and cash flow smoothing are other factors that have defined the optimum timing to complete the project for the Group 2 replacement as 2025. We forecast that construction work will start in 2021 and end in 2025.

8.5 Demand Management

An analysis of non-network options considered how demand management could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative. The cost benefit assessment has shown that non-network alternatives were not found to be cost effective.

Note that at this early stage there is little or no specific information known about actual non-network options available in the area, so assumptions are made about the likely scale of demand reductions possible and the estimated costs. These assumptions are based upon previous experience with delivery of demand management projects, submissions to non-network options reports from non-network solution providers and lessons learned from demand management trials by Ausgrid and others.

As part of the Rules requirements, a RIT-D will be conducted on this project, and a NNOR will be published as part of the demand management engagement process. This will inform interested parties of the opportunity identified, and invite submissions from non-network proponents. If during the consultation process a non-network option is found to offer a cost effective alternative to the preferred network option, the selected solution to the need will be modified accordingly.

8.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project is outlined in the table below.

Table 7. Project cash flow ($m, real FY19)

	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network Option	-	-	0.03	0.9	5.1	6.9	0.6

9 PROJECT 7 - MIRANDA

9.1 Project description

The project is to replace the existing 11kV switchgear at Miranda Zone Substation in the Sutherland region of Ausgrid's network. The compound insulated switchgear is nearing the end of its life, and based on our cost-benefit analysis the asset should be replaced by 2025. The option analysis suggests that the asset should be replaced with modern equivalent switchgear. The total project cost is $12.6 million of which $11.3 million is forecast to be incurred in the 2019-24 period.

This work was previously planned for completion by 2021, and includes an extension of the present 11kV switch room.

Figure 14. Miranda Zone Substation

9.2 Need

Miranda 33/11kV Zone Substation is supplied via three 33kV feeders from Port Hacking Subtransmission Substation. Miranda Zone Substation was commissioned in 1957.

Miranda Zone Substation comprises two groups of double busbar compound insulated 11kV switchgear with vacuum circuit breakers. The 11kV compound switchboards are two types of Email switchboards and both were recommended for replacement in 2021 in Ausgrid's switchboard replacement program, based on a condition assessment that identified reliability and safety risks.

Based on an assessment that the 33kV oil circuit breaker circuit breakers posed a serious reliability risk, they were replaced in 2010 with the SF6 vacuum outdoor circuit breakers mentioned above. However these replacement circuit breakers are now also considered to be in poor condition due to leaking of SF6 gas, even though they are relatively new. This issue was a consideration when assessing the options, but it is not addressed in this project.

The main considerations driving the replacement of the 11kV switchgear at Miranda zone are the expected contribution to unserved energy and safety risks.

9.3 Options

We examined the following options as part of the Ausgrid's planning process:

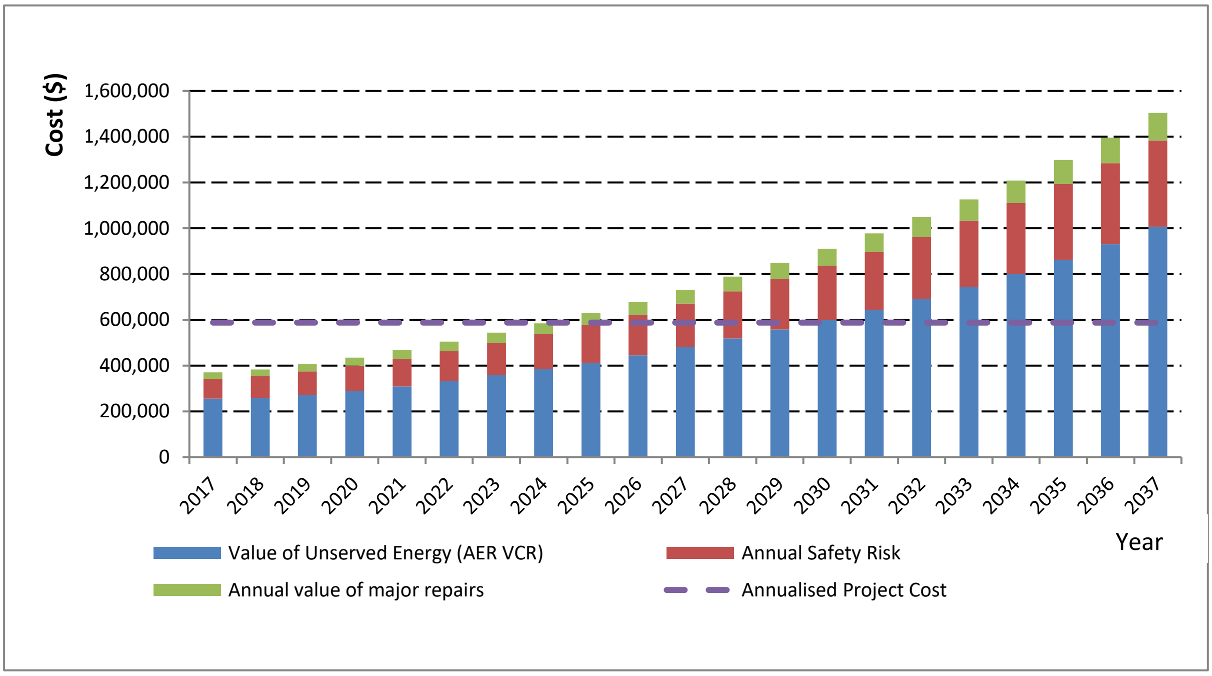
1. Replacement of 11kV switchgear at Miranda Zone Substation in a new switch room on the existing site.
2. Retirement of Miranda Zone Substation via 11kV load transfers to surrounding zones.
3. Construction of a new 33/11kV Zone Substation to replace the existing Miranda Zone Substation.
4. Consideration of demand management.

The preferred and most cost effective network solution to resolve issues at Miranda Zone Substation is Option 1, namely to replace 11kV switchgear in a new switch room on the Miranda Zone Substation site. This project does not involve or resolve other issues in the area.

9.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date of 2025 as illustrated in the cost and benefit graph below.

Figure 15. Total risk cost versus project deferral benefit



This timing is also driven by the need to coordinate the work while maintaining the required levels of reliability to customers. This, and deliverability, resource availability and cash flow smoothing define an optimum timing for completion of the project as 2025.

We anticipate that work will start in 2021 and end in 2025.

9.5 Demand Management

An analysis of non-network options considered how demand management could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative. The cost benefit assessment has shown that non-network alternatives were not found to be cost effective.

Note that at this early stage there is little or no specific information known about actual non-network options available in the area, so assumptions are made about the likely scale of demand reductions possible and the estimated costs. These assumptions are based upon previous experience with delivery of demand management projects, submissions to non-network options reports from non-network solution providers and lessons learned from demand management trials by Ausgrid and others.

As part of the Rules requirements, a RIT-D will be conducted on this project, and a NNOR will be published as part of the demand management engagement process. This will inform interested parties of the opportunity identified, and invite submissions from non-network proponents. If during the consultation process a non-network option is found to offer a cost effective alternative to the preferred network option, the selected solution to the need will be modified accordingly.

9.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project is outlined in the table below.

Table 8. Project cash flow ($m, real FY19)

	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network Option	-	-	0.4	1.5	3.8	5.5	1.3

10 PROJECT 8 - TARRO

10.1 Project description

The project is to retire the existing 11kV switchgear at Tarro Zone Substation in the Maitland region of Ausgrid's network. The compound insulated switchgear is nearing the end of its life, and based on our cost-benefit analysis and other considerations these assets should be retired by the end of 2022. Our option analysis suggests that the asset should be replaced with modern equivalent switchgear. The total project cost is $9.8 million, of which $7.9 million is forecast to be incurred in the 2019-24 period.

Figure 16. Tarro Zone Substation

10.2 Need

Tarro 33/11kV Zone Substation is supplied via two 33kV feeders from Beresfield Subtransmission Substation. Tarro Zone Substation, which was commissioned in 1960, comprises compound-insulated 11kV switchgear and has been assessed as being in poor condition. Although some measures have been implemented to mitigate these issues, this type of switchgear is considered to be beyond its design life, with continued service resulting in increasing risk of failure.

Using Ausgrid's asset prioritisation process, the compound 11kV switchgear at Tarro Zone Substation is recommended for retirement within 10 to 20 years. This is later than the date determined by cost benefit analysis.

The main consideration driving the retirement of 11kV switchgear at Tarro Zone Substation is its contribution to expected unserved energy.

10.3 Options

We examined the following options as part of Ausgrid's planning process:

1. Replacement of 11kV switchgear at Tarro Zone Substation in a new switchroom within the existing site.
2. Replacement of Tarro Zone Substation by constructing a new 132/11kV Beresfield zone.
3. Replacement of 11kV switchgear at Tarro Zone Substation using temporary partial load transfer to Thornton zone.

4. Retirement of Tarro Zone Substation by permanently transferring its load to adjacent zone substations.
5. Consideration of demand management.

The preferred and most cost effective network option to resolve issues at Tarro Zone Substation is Option 3, namely to replace 11kV switchgear at Tarro Zone using partial load transfer to Thornton Zone. This project does not involve or resolve other issues in the area.

10.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date of 2017 as illustrated in the cost and benefit graph below.

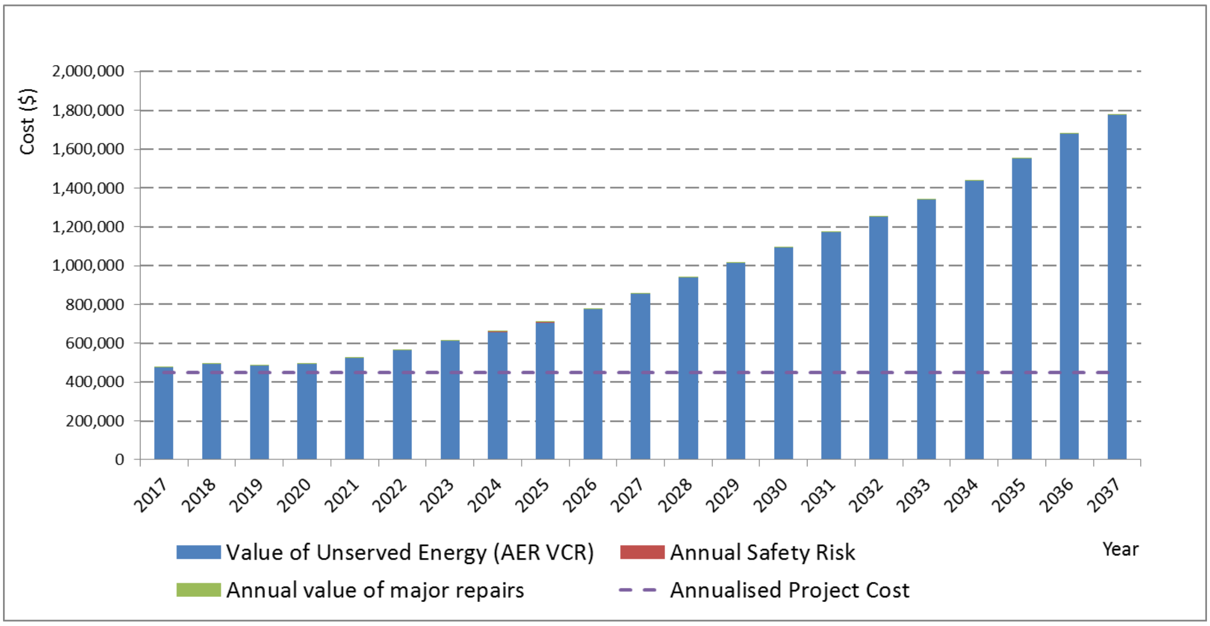


Figure 17. Total risk cost versus project deferral benefit

Timing is also driven by the need to coordinate the work with the replacement of other assets while maintaining the required levels of reliability to customers. Deliverability, resource availability and cash flow smoothing define a practical completion date of the project of 2022.

Construction work will start in 2018 and end in 2022.

10.5 Demand Management

An analysis of non-network options considered how demand management could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative. The cost benefit assessment has shown that non-network alternatives were not found to be cost effective.

Note that at this early stage there is little or no specific information known about actual non-network options available in the area, so assumptions are made about the likely scale of demand reductions possible and the estimated costs. These assumptions are based upon previous experience with delivery of demand management projects, submissions to non-network options reports from non-network solution providers and lessons learned from demand management trials by Ausgrid and others.

As part of the Rules requirements, a RIT-D will be conducted on this project, and a NNOR will be published as part of the demand management engagement process. This will inform interested parties of the opportunity identified, and invite submissions from non-network proponents. If during the consultation process a non-network option is found to offer a cost effective alternative to the preferred network option, the selected solution to the need will be modified accordingly.

10.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project is outlined in the table below.

Table 9. Project cash flow ($m, real FY19)

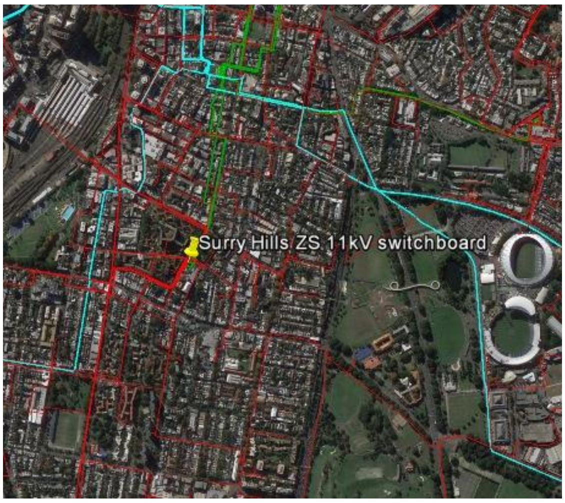
	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network Option	1.9	5.3	2.3	0.4	-	-	-

11 PROJECT 9 – SURRY HILLS

11.1 Project description

The project is to replace the existing 11kV switchgear at Surry Hills Zone Substation in the Eastern Suburbs region of Ausgrid's network. The compound-insulated switchgear is nearing the end of its life, and based on Ausgrid's asset prioritisation process, the asset is recommended for replacement in less than 5 years. The options analysis suggests that the asset should be replaced with modern equivalent switchgear on the existing site. Replacement of 11kV switchgear at Surry Hills zone is a committed project that is under construction and is planned to be completed in 2020. The total project cost is $13.6 million, of which $5.7 million is forecast to be incurred in the 2019-24 period.

Figure 18. Surry Hills Zone Substation



11.2 Need

Surry Hills 33/11kV Zone Substation is supplied via 33kV gas feeders from Surry Hills Subtransmission Substation. These feeders are directly connected to four 33/11kV transformers at Surry Hills Zone Substation.

Surry Hills Zone Substation comprises three groups of double busbar compound-insulated switchgear and all groups are at the end of their service lives.

This project is committed, and is under construction. It is anticipated that it will be completed in 2019/20.

11.3 Options

We examined the following options for retirement of the 11kV switchgear at Surry Hills Zone Substation as part of Ausgrid's planning process:

1. Replacement of 11kV switchgear at Surry Hills Zone Substation in the existing switchroom by temporarily transferring load to adjacent zones.
2. Retire 11kV switchgear by transferring load to adjacent zones, and decommission Surry Hills Zone Substation.
3. New Surry Hills 33/11kV Zone Substation.
4. Consideration of demand management.

The selected network solution at Surry Hills Zone Substation is Option 1, namely to replace 11kV switchgear within the existing switchroom, requiring temporary load transfers to other zones. This project does not involve or resolve other issues in the area.

11.4 Timing

This project is already committed and is under construction. The anticipated completion date is by 2020/21.

The construction work is in progress and expected to end in 2021.

11.5 Demand Management

This project is already in progress, and as such it is not feasible to use demand management to defer the timing of this project.

11.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project as a whole is outlined in the table below.

Table 10. Project cash flow ($m, real FY19)

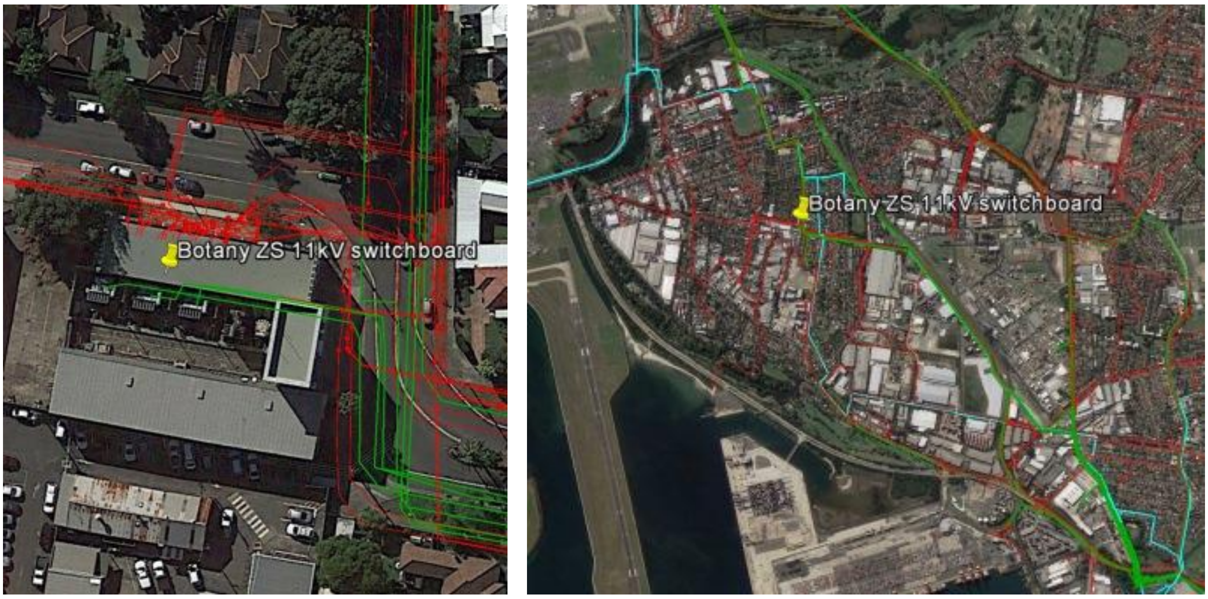
	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network Option	8.0	5.6	0.08	-	-	-	-

12 PROJECT 10 - BOTANY

12.1 Project description

The project is to replace the existing 11kV switchgear (Group 1) at Botany Zone Substation in the Eastern Suburbs region of Ausgrid's network. The compound-insulated switchgear is nearing the end of its life, and based on our cost-benefit analysis the asset should be replaced by 2025. Our options analysis suggests that the asset should be replaced with modern equivalent switchgear on the existing site. The total project cost is $5.7 million of which $5.4 million is forecast to be incurred in the 2019-24 period.

Figure 19. Botany Zone Substation



12.2 Need

Botany 33/11kV Zone Substation is supplied via 33kV cables from Bunnerong North Subtransmission Substation. These cables are directly connected to four 33/11kV transformers at Botany zone. Botany Zone was commissioned in 1950.

Botany Zone Substation comprises three groups of double busbar compound-insulated switchgear. Group 1 and 3 use vacuum circuit breakers whereas Group 2 still uses oil circuit breakers due to the unavailability of compatible vacuum circuit breaker trucks. There is a committed project to replace Group 2 and Group 3 switchgear by installing a new section of single busbar switchgear in the existing switchroom by April 2019.

The Group 1 switchgear has been prioritised for replacement by 2024.

The 33kV feeders supplying Botany zone are paper insulated (HSL) cables, and have been assessed as having limited remaining reliable service life. These cables have been prioritised for replacement beyond 2024.

The main considerations driving the replacement of the 11kV switchgear at Botany zone are its contribution to expected unserved energy and safety risks.

12.3 Options

We examined the following options for the Group 1 switchgear as part of Ausgrid's planning process:

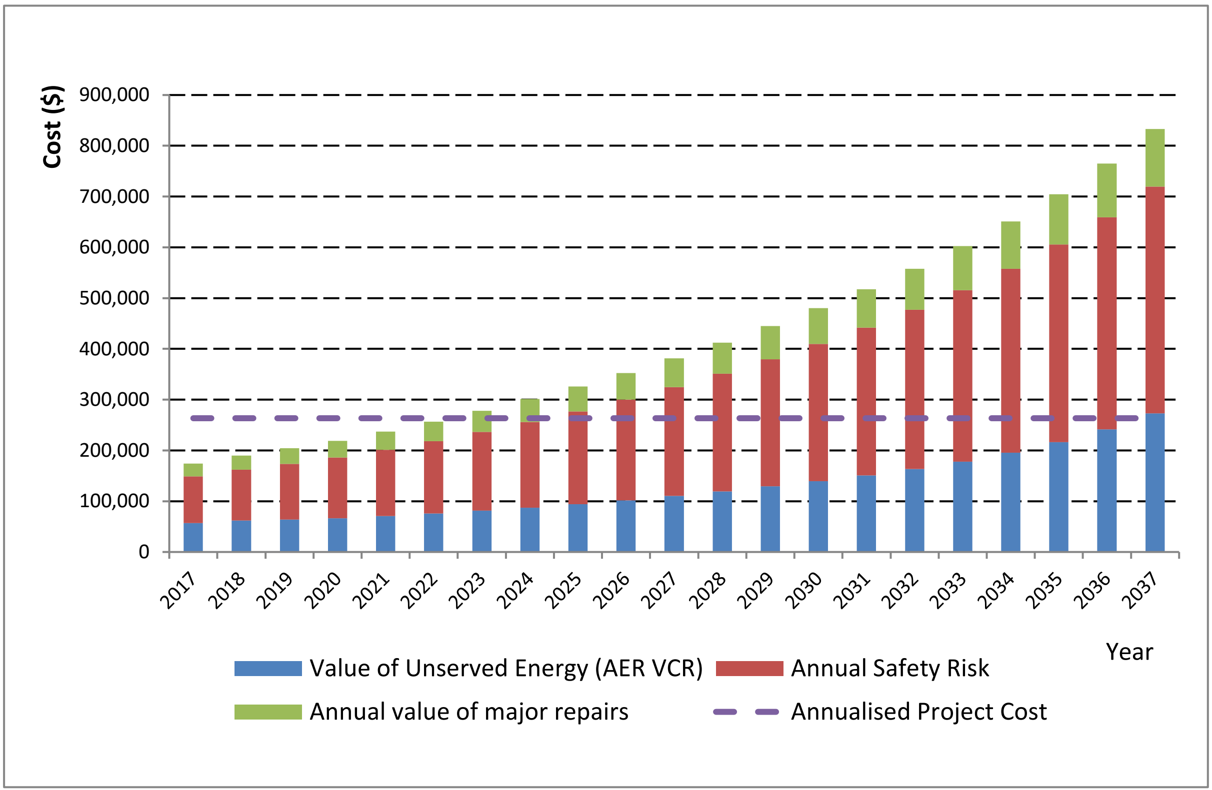
1. Replacement of 11kV Group 1 switchgear in the existing switchroom by temporarily transferring load to adjacent zones.
2. Retirement of 11kV Group 1 switchgear by transferring load to adjacent zones, allowing decommissioning of one transformer.
3. Retire Botany zone by transferring all load to adjacent zones.
4. Consideration of demand management.

The preferred and most cost effective network solution to resolve issues at Botany Zone Substation is Option 1, namely to replace Group 1 11kV switchgear within the existing switchroom using temporary load transfer to adjacent zone substations. This project does not involve or resolve other issues in the area.

12.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date of 2023 as illustrated in the cost and benefit graph below.

Figure 20. Total risk cost versus project deferral benefit



Timing is also driven by the need to coordinate the work with the replacement of other while maintaining the required levels of reliability to customers. Deliverability, resource availability and cash flow smoothing define a new optimum timing for completion of the replacement of Group 1 switchgear of 2025.

We forecast that construction work will start in 2022 and end in 2025.

12.5 Demand Management

An analysis of non-network options considered how demand management could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative. The cost benefit assessment has shown that non-network alternatives were not found to be cost effective.

Note that at this early stage there is little or no specific information known about actual non-network options available in the area, so assumptions are made about the likely scale of demand reductions possible and the estimated costs. These assumptions are based upon previous experience with delivery of demand management projects, submissions to non-network options reports from non-network solution providers and lessons learned from demand management trials by Ausgrid and others.

As part of the Rules requirements, a RIT-D will be conducted on this project, and a NNOR will be published as part of the demand management engagement process. This will inform interested parties of the opportunity identified, and invite submissions from non-network proponents. If during the consultation process a non-network option is found to offer a cost effective alternative to the preferred network option, the selected solution to the need will be modified accordingly.

12.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project as a whole is outlined in the table below.

Table 11. Project cash flow ($m, real FY19)

	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network Option	-	-	-	0.2	1.0	4.1	0.4

13 PROJECT 11 - LIDCOMBE

13.1 Project description

The project is to retire and replace the existing 11kV switchgear at Lidcombe 33/11kV Zone Substation in the Inner West region of Ausgrid's network. The compound insulated 11kV switchgear at Lidcombe is nearing the end of its life, and is considered to pose a risk to reliability of supply in that zone. Based on Ausgrid's asset prioritisation process, Group 2 of the 11kV switchgear at Lidcombe Zone Substation is recommended for replacement within the next five years, and Group 1 of the 11kV switchgear in the next five to 10 years. The replacement options and timing analysis took into account that some of the 33kV cables that supply Lidcombe and Auburn Zones from Homebush STS are also in need of replacement.

The preferred network option on the basis of economic and strategic analysis is to replace the Lidcombe switchgear in two groups within the same switch room and to replace the most deteriorated 33kV cables using feeders from the Endeavour Energy network. Commitment to replacement of one switchgear group (Group 2) is anticipated shortly, for completion by 2021. The total project cost for both Groups of 11kV switchgear works is $24.4 million, of which $5.1 million is forecast to be incurred in the 2019-24 regulatory period.

Figure 21. Lidcombe Zone Substation

13.2 Need

Lidcombe 33/11kV Zone Substation is supplied by 33kV cables from Homebush Subtransmission Substation (STS).

The critical asset conditions at Lidcombe Zone Substation are:

- The compound-insulated 11kV switchgear at Lidcombe Zone Substation has limited remaining life. Some have been prioritised for replacement within five years, and the remainder within 10 years, because the oil circuit breakers of the second group are already being replaced with vacuum circuit breakers.
- The 33kV cables that connect Homebush STS to both Auburn and Lidcombe Zone Substation use a combination of gas-filled and HSL technology. The gas-filled cable sections were prioritised for replacement before 2015. HSL feeder 605 had been prioritised for replacement before 2023, but it has recently been reassessed for a longer

life. The current configuration of feeders is limiting the capacity of both Auburn and Lidcombe Zone Substations.

There are also similar 11kV condition issues at the nearby Auburn Zone Substation, and the option analysis sought an integrated solution to all these needs.

The main consideration driving the replacement of the 11kV switchgear at Lidcombe zone is its contribution to expected unserved energy.

13.3 Options

A large range of options has been evaluated over several years, under different assumptions about the remaining life of switchgear and cables. A recent development has been the availability of capacity from Endeavour Energy's network, following the closure of a petroleum refinery plant at nearby Camellia. This provided the opportunity of sourcing 33kV supply using predominantly overhead lines to supply both Auburn and Lidcombe, as an alternative to supply from Ausgrid's Homebush STS.

As part of Ausgrid's planning process, the sub-options that were evaluated in various combinations for replacing the 11kV switchgear at Lidcombe and Auburn and the cables from Homebush STS included:

1. Replacing the 33kV cables between Homebush STS and Lidcombe and Auburn Zones, using current XLPE technology.
2. A mixture of 33kV overhead construction and continued use of some existing HSL cables that have a reasonable assessed remaining life to supply Lidcombe and Auburn from Camellia in Endeavour Energy's network.
3. Taking 132kV supply from a nearby overhead line, to supply a new 132/11kV Zone in the Auburn/ Lidcombe area, and transferring some or all of the load to it.
4. Retirement of Auburn, Lidcombe or both Zones by transfer of all load to adjacent zones;
5. Replacement of 11kV switchgear and associated refurbishment on the existing sites of Auburn and Lidcombe.
6. Replacement of one or both Zone Substations by building on a new site near Lidcombe and/or Auburn.
7. Consideration of demand management.

The preferred and most cost effective network option is a combination of sub-options 2 and 5, namely taking 33kV supply from Camellia, and replacing the 11kV switchgear within the existing buildings. It is the most cost effective network option. It can be arranged to provide increased firm 33kV capacity, and it can be staged so that switchgear can be replaced according to its different assessed conditions.

13.4 Timing

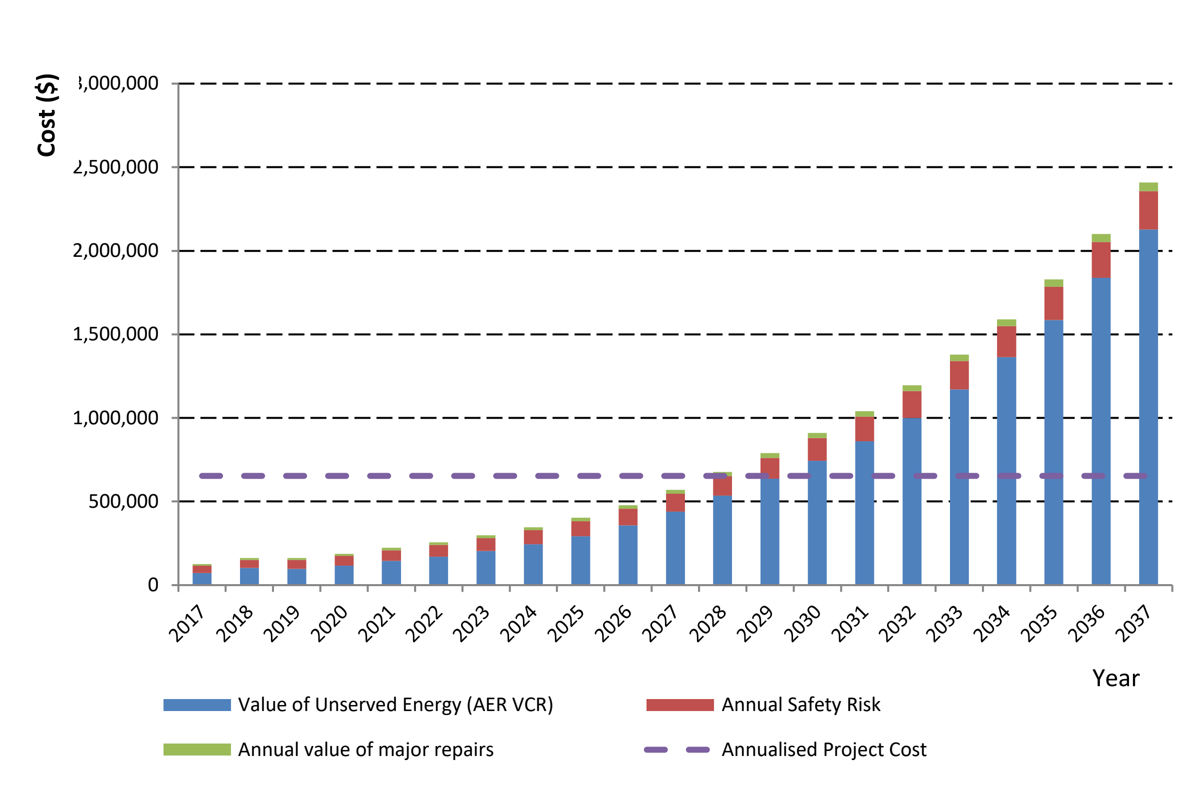
In respect of Lidcombe, the Group 2 11kV switchgear has been assessed as requiring replacement within five years. Construction will be committed and will commence shortly to achieve completion by 2021.

The works to take 33kV supply from Camellia TS is also about to commence, allowing decommissioning of the aged 33kV gas cables from Homebush by March 2020. This is not part of this project, but may impact on timing.

As the project to replace the 33kV feeders and 11kV Group 2 switchgear at Lidcombe zone is committed, cost benefit analysis is not relevant to this group.

In accordance with Ausgrid's asset prioritisation process, the Group 1 11kV switchgear at Lidcombe has been assessed as requiring replacement within 10 years. We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date of 2028 as illustrated in the cost and benefit graph below. Based on deliverability and resource availability, the optimum delivery date of the preferred network solution is 2028.

Figure 22. Total risk cost versus project deferral benefit (Group 1 Switchgear)



13.5 Demand Management

As the Group 2 11kV switchgear replacement project is already in progress, it is not feasible to use demand management to defer the timing of this project.

For the Group 1 11kV switchgear replacement project, an analysis of non-network options considered how demand management could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative.

The cost benefit assessment has shown that the non-network option is able to efficiently reduce the estimated unserved energy at risk in advance of the completion date and a deferral of the preferred network option by three years from 2028 to 2031. As such, this option is the preferred option. Details on the capital and operating expenditure impacts are found in Chapter 5 (Capital expenditure) and Chapter 6 (Operating expenditure) of the regulatory proposal.

Note that at this early stage there is little or no specific information known about actual non-network options available in the area, so assumptions are made about the likely scale of demand reductions possible and estimated costs. These assumptions are based upon previous experience with delivery of demand management projects, submissions to non-network options reports from non-network solution providers and lessons learned from demand management trials by Ausgrid and others.

As part of the Rules requirements, a RIT-D will be conducted on this project, and a NNOR will be published as part of the demand management engagement process. This will inform interested parties of the opportunity identified, and invite submissions from non-network proponents. Where the RIT-D process or any consequent tender for non-network solutions indicates that a modified non-network scope of work offers an improved cost benefit outcome, the selected solution to the need will be modified accordingly.

We forecast that construction work for the preferred network option for Group 1 11kV switchgear (including demand management) will start in 2026/27 for completion by 2030/31.

13.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project to replace two Groups of 11kV switchgear at Lidcombe Zone Substation, including both the network option and the preferred option including demand management, are outlined in the table below.

Table 12. Project cash flow ($m, real FY19)

	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Group 2 Network Option (preferred)	4.1	2.4	2.4	0.2*			
Group 1 Network Option						0.4	13.7**
Group 1 DM Option (preferred)							15.2

* This project is for Group 2 Lidcombe 11kV switchgear replacement

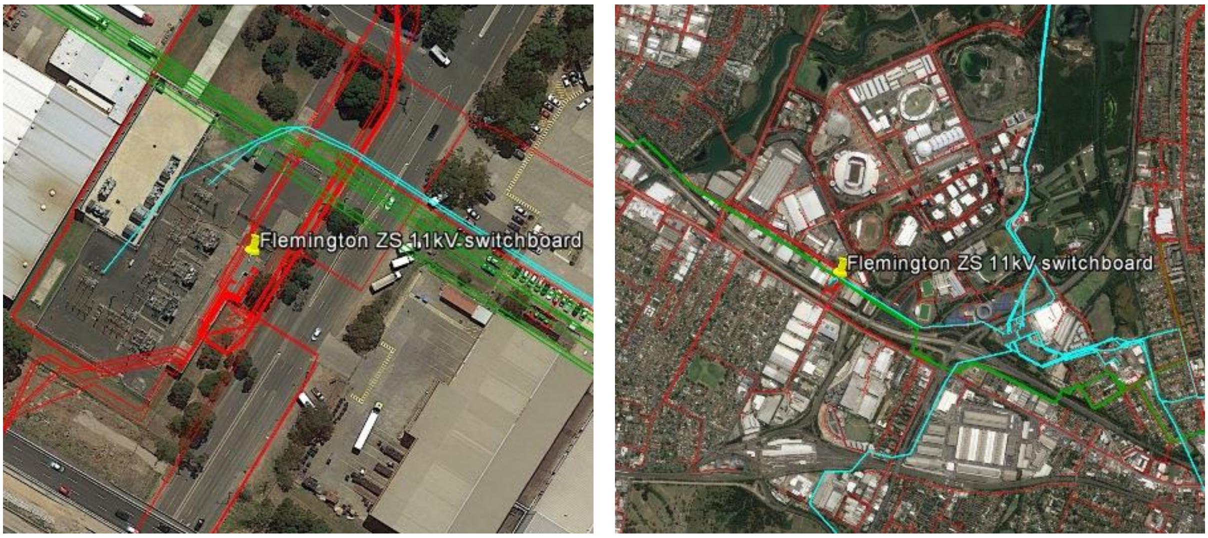
** This project is for Group 1 Lidcombe switchgear replacement & feeder 61H

14 PROJECT 12 - FLEMINGTON

14.1 Project description

The project is to retire and replace the existing 11kV compound insulated switchgear at Flemington 132/11kV Zone Substation in the Inner West region of Ausgrid's network. The compound-insulated switchgear at Flemington is nearing the end of its life, and is considered to pose a risk to reliability of supply in that zone. The option chosen on the basis of economic and strategic analysis is to decommission the compound insulated 11kV switchgear (Group 1) by transferring the load to the new Olympic Park Zone Substation and reconfiguring Flemington Zone from four to two transformers by 2021. The total project cost for the 11kV load transfer and switchgear decommissioning works is $6.2 million, of which $4.4 million is forecast to be incurred in the 2019-24 period.

Figure 23. Flemington Zone Substation



14.2 Need

Flemington 132/11kV Zone Substation was commissioned in 1973 and is supplied via two 132kV feeders 200 and 201 from Mason Park STS.

The 11kV switchgear at Flemington Zone Substation consists of both compound and air insulated types. Group 1 of the 11kV switchgear supplied by transformers Tx1 and Tx3 is a Westinghouse HQ type compound switchboard, which is in poor condition and has been recommended for replacement.

Due to the poor condition of its tap changer, transformer Tx1 is on fixed tap and is operating as a hot (energised) standby. Transformers Tx2 and Tx4 are also known to be in poor condition and are approaching their end of life.

The main consideration driving the retirement of the 11kV switchgear at Flemington zone is the contribution to expected unserved energy.

14.3 Options

We assessed the following options as part of Ausgrid's planning process:

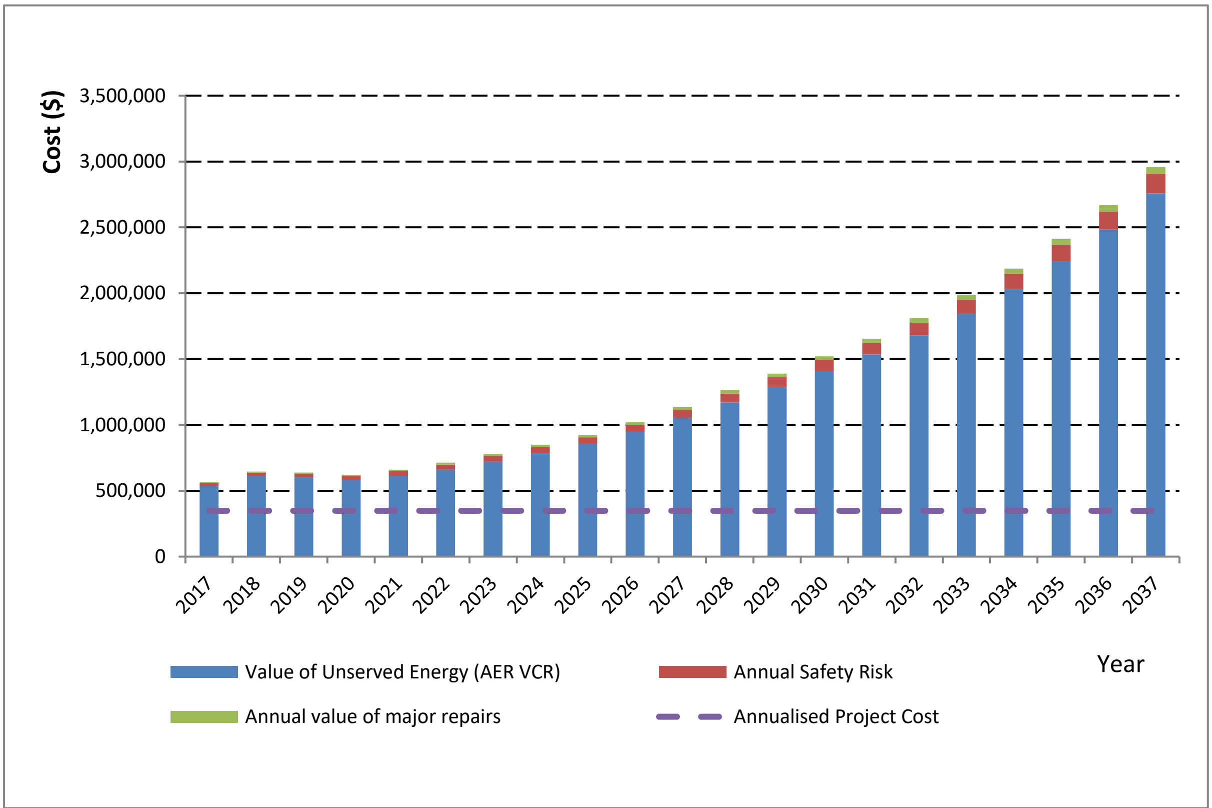
1. Refurbishment of Flemington zone which would involve temporary load transfer to adjacent zone substations while undertaking staged replacement of Group 1 11kV switchgear in the existing switchroom.
2. Retirement of Group 1 compound insulated 11kV switchgear by transferring load permanently to Olympic Park zone and reconfigure Flemington Zone from four to two transformers.
3. Replacement of Flemington Group 1 compound insulated 11kV switchgear in a new switchroom.
4. Consideration of demand management.

The preferred network solution is Option 2, namely to retire Group 1 compound insulated 11kV switchgear by transferring its load permanently to Olympic Park Zone Substation. The two most reliable transformers will be re-configured to supply the remaining load.

14.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date of 2017 as illustrated in the cost and benefit graph below.

Figure 24. Total risk cost versus project deferral benefit



Timing is also driven by the need to coordinate the work with the replacement of other assets while maintaining the required levels of reliability to customers. Deliverability, resource availability and cash flow smoothing define a practical completion date of the project of 2021.

We forecast that construction work will start in 2018 and end in 2021.

14.5 Demand Management

An analysis of non-network options considered how demand management could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative. The cost benefit assessment has shown that non-network alternatives were not found to be cost effective.

Note that at this early stage there is little or no specific information known about actual non-network options available in the area, so assumptions are made about the likely scale of demand reductions possible and the estimated costs. These assumptions are based upon previous experience with delivery of demand management projects, submissions to non-network options reports from non-network solution providers and lessons learned from demand management trials by Ausgrid and others.

As part of the Rules requirements, a RIT-D will be conducted on this project, and a NNOR will be published as part of the demand management engagement process. This will inform interested parties of the opportunity identified, and invite submissions from non-network proponents. If during the consultation process a non-network option is found to offer a cost effective alternative to the preferred network option, the selected solution to the need will be modified accordingly.

14.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project to decommission Group 1 11kV switchgear at Flemington Zone Substation is outlined in the table below.

Table 13. Project cash flow ($m, real FY19)

	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network Option	3.2	1.2	-	-	-	-	-

15 PROJECT 13 - STOCKTON

15.1 Project description

The project is to replace the existing 11kV switchgear at Stockton in the Newcastle region of Ausgrid's network. The compound insulated switchgear is nearing the end of its life, and based on our cost-benefit analysis and other considerations the switchgear should be replaced by 2022. Our options analysis suggests that the asset should be replaced with modern equivalent switchgear, requiring construction of a new switch room with control and protection changes. The total project cost is $5.5 million, of which $4.4 million is forecast to be incurred in the 2019-24 period.

Figure 25. Stockton Zone Substation

15.2 Need

Stockton 33/11kV Zone Substation, which was commissioned in 1968, is supplied by two 33kV overhead lines from Williamstown, with tail-ended transformers.

Stockton Zone Substation comprises compound insulated 11kV switchgear with oil circuit breakers and these assets have been assessed as being in poor condition. As a result of current prioritisation, the 11kV switchgear at Stockton Zone Substation is recommended for retirement within five to ten years.

The main consideration driving the replacement of the 11kV switchgear at Stockton Zone is its contribution to expected unserved energy.

15.3 Options

We examined the following options as part of Ausgrid's planning process:

1. Replacement of 11kV switchgear at Stockton Zone Substation in a new switchroom.
2. Retirement of Stockton Zone Substation via 11kV load transfers to a surrounding zone. This option is not feasible as the only adjacent zone is Williamstown which is over 10km away.
3. Establishment of a new Stockton Zone Substation.

4. Consideration of demand management.

The preferred and most cost effective network solution to resolve issues at Stockton Zone Substation is Option 1, namely to replace the 11kV switchgear in a new switchroom on the existing site. This project does not involve or resolve other issues in the area.

15.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date as early as possible, as illustrated in the cost and benefit graph below.

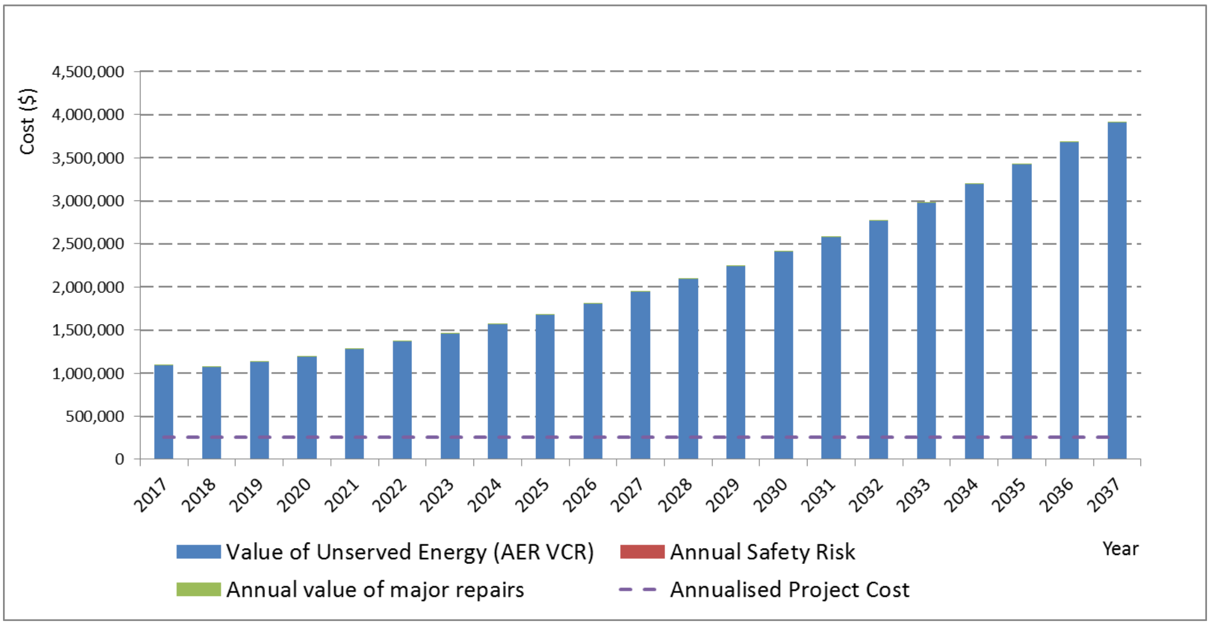


Figure 26. Total risk cost versus project deferral benefit

This timing is also driven by deliverability, resource availability and cash flow smoothing. In consideration of these factors, the practical completion for this project is 2022.

Construction work will start in 2018 and end in 2022.

15.5 Demand Management

An analysis of non-network options considered how demand management could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative. The cost benefit assessment has shown that non-network alternatives were not found to be cost effective.

Note that at this early stage there is little or no specific information known about actual non-network options available in the area, so assumptions are made about the likely scale of demand reductions possible and the estimated costs. These assumptions are based upon previous experience with delivery of demand management projects, submissions to non-network options reports from non-network solution providers and lessons learned from demand management trials by Ausgrid and others.

As part of the Rules requirements, a RIT-D will be conducted on this project, and a NNOR will be published as part of the demand management engagement process. This will inform interested parties of the opportunity identified, and invite submissions from non-network proponents. If during the consultation process a non-network option is found to offer a cost effective alternative to the preferred network option, the selected solution to the need will be modified accordingly.

15.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project is outlined in the table below.

Table 14. Project cash flow ($m, real FY19)

	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network Option	1.1	3.7	0.7	0.01	-	-	-

16 PROJECT 14 - DENMAN

16.1 Project description

The project is to replace the existing 11kV switchgear at Denman 66/11kV Zone Substation in the Upper Hunter area of Ausgrid's network. The "South Wales" brand of air-insulated switchgear is the last of its kind in the entire Ausgrid network and is also nearing the end of its life. Based on our cost-benefit analysis the switchgear should be replaced by 2021. Our options analysis suggests that the asset should be replaced with modern equivalent modular switchgear, requiring construction of a new switch room with control and protection changes. The total project cost is $4.0 million, of which $3.6 million is forecast to be incurred in the 2019-24 period.

Figure 27. Denman Zone Substation

16.2 Need

Denman 66/11kV Zone Substation is supplied by 66kV overhead lines from Mitchell Line Subtransmission Station. The electrical equipment dates from 1985, but the original plant is assessed as approaching the end of its service life.

The 11kV switchgear is of "South Wales" type and Denman has the last of this type of board on the Ausgrid Network. Spare parts for any corrective or preventative maintenance are difficult to procure and this poses a significant reliability risk to Ausgrid. Ausgrid has determined that this situation is unacceptable, and has prioritised retirement of this switchboard as the only viable solution.

The main consideration driving the replacement of the 11kV switchgear at Denman zone is the contribution to expected unserved energy which is exacerbated by the presence of orphan switchgear.

16.3 Options

We examined the following options as part of Ausgrid's planning process:

1. Replacement of 11kV switchgear at Denman Zone Substation in a new switch room.
2. Retirement of Denman Zone Substation via 11kV load transfers to a surrounding Zone. This option is not feasible as there are no adjacent zones with sufficient capacity.
3. Establishment of a new Denman Zone Substation.

4. Consideration of Demand Management.

The most economical network solution is Option 1, namely to refurbish the existing Denman 66/11kV Zone Substation to address the aged orphan asset issues, by constructing a new 11kV switch room on available land inside the existing substation site. This project does not involve or resolve other issues in the area.

16.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date of 2021 as illustrated in the cost and benefit graph below.

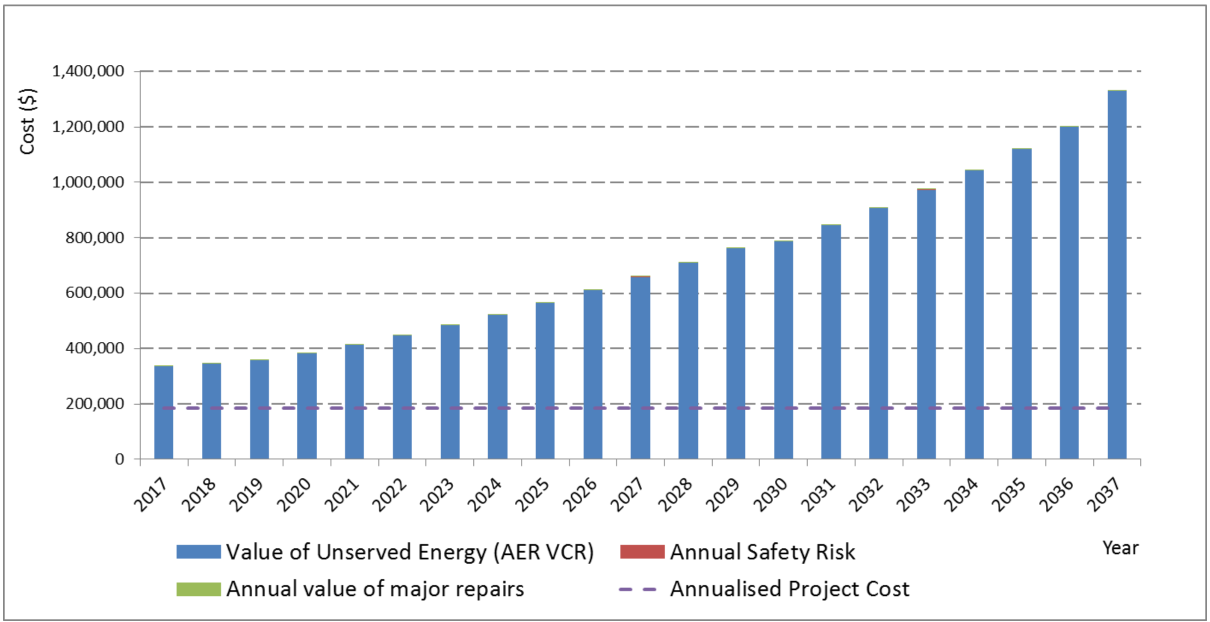


Figure 28. Total risk cost versus project deferral benefit

Work will start in 2018 and is anticipated to end in 2021.

16.5 Demand Management

An analysis of non-network options considered how demand management could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative. The cost benefit assessment has shown that non-network alternatives were not found to be cost effective.

Note that at this early stage there is little or no specific information known about actual non-network options available in the area, so assumptions are made about the likely scale of demand reductions possible and the estimated costs. These assumptions are based upon previous experience with delivery of demand management projects, submissions to non-network options reports from non-network solution providers and lessons learned from demand management trials by Ausgrid and others.

Where required under the Rules requirements, a RIT-D will be conducted on this project, and a NNOR published as part of the demand management engagement process. This will inform interested parties of the opportunity identified, and invite submissions from non-network proponents. If during a consultation process a non-network option is found to offer a cost effective alternative to the preferred network option, the selected solution to the need will be modified accordingly.

16.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project is outlined in the table below.

Table 15. Project cash flow ($m, real FY19)

	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network Option	0.4	2.1	1.5	-	-	-	-

17 PROJECT 15 - DARLINGHURST

17.1 Project description

The project is a multi-staged retirement (Stages 1 and 2) of the existing 11kV switchgear at Darlinghurst 33/11kV Zone Substation in the Eastern Suburbs region of Ausgrid's network. Based on Ausgrid's prioritisation process, the staged retirement aims to address the asset conditions with the highest risk profile first, independently of the remaining assets with lower risk profiles.

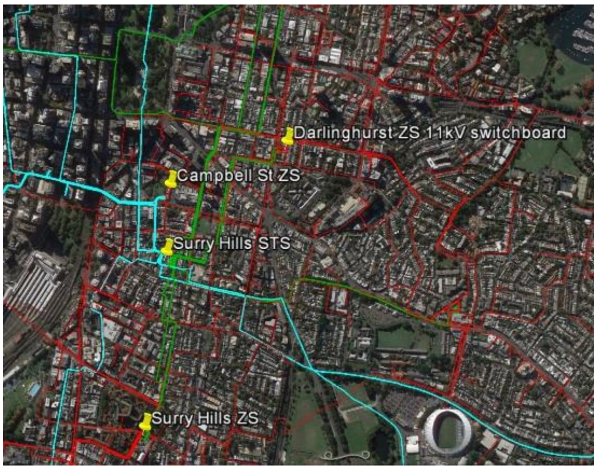
The 11kV switchgear at Darlinghurst Zone Substation comprises both compound insulated and air insulated switchgear. The 11kV switchgear is considered to pose a risk to reliability of supply. Based on Ausgrid's prioritisation process, the 11kV compound switchgear at Darlinghurst Zone Substation is recommended for retirement within five to 10 years. The preferred network option for Stage 1 on the basis of economic and strategic analysis is to transfer half of the Darlinghurst Zone Substation load to the adjacent Campbell St Zone Substation, transfer some load from Campbell St to Surry Hills Zone Substation and to decommission the 11kV compound switchgear along with Transformers 1 and 2 and associated 33kV feeders 387 and 388.

Based on Ausgrid's prioritisation process, the 11kV air insulated switchgear at Darlinghurst Zone Substation is recommended for retirement within 10 to 20 years. The preferred network option for Stage 2 is to transfer the remaining half of the Darlinghurst Zone Substation load to the adjacent Campbell St Zone Substation, install additional 11kV switchgear at Campbell St Zone Substation, and to decommission the 11kV air insulated switchgear along with Transformers 3 and 4 and associated 33kV feeders 386 and 389 post the 2019-24 period. The timing analysis for Stage 2 will be subject to ongoing annual review.

The options and timing analysis for the staged retirement recognised that the 33kV gas filled cables that supply Darlinghurst Zone Substation are also near the end of their serviceable lives.

The total project cost for Stage 1 is $3.8 million, of which $3.3 million is forecast to be incurred in the 2019-24 period. The total project cost for Stage 2 is $13.6 million which is forecast to be incurred outside the 2019-24 period.

Figure 29. Darlinghurst Zone Substation



17.2 Need

Darlinghurst 33/11kV Zone Substation is located outside the eastern boundary of the Sydney CBD, and is supplied by four gas filled 33kV cables from Surry Hills STS. The critical asset conditions at Darlinghurst Zone Substation are as follows:

- **33kV gas-insulated feeders 386, 387, 388 and 389**

  The 33kV feeders between Surry Hills STS and Darlinghurst ZS comprise gas pressure cables where the majority of these cables are approaching the end of their service life. Ausgrid has a plan to retire all gas cables by the end of financial year 2029. The 33kV feeder 387 between Surry Hills STS and Darlinghurst Zone Substation was recommended for retirement in 2015. The optimum retirement date for the remaining 33kV feeders will be subject to ongoing annual review.

- **11kV Compound-insulated switchgear**

  One group of the 11kV switchgear at Darlinghurst Zone Substation is compound-filled. The compound-filled 11kV switchgear at Darlinghurst Zone Substation is recommended for retirement before 2026 based on Ausgrid's asset prioritisation process, but it is economic to bring this forward to enable retirement of the associated 33kV gas filled cables.

- **11kV air-insulated switchgear**

  Two groups of the 11kV switchgear at Darlinghurst Zone Substation are air-insulated. The air-insulated 11kV switchgear at Darlinghurst Zone Substation is recommended for retirement from 2026 to 2036, based on Ausgrid's asset prioritisation process. The optimum retirement date will be subject to ongoing annual review. Again, it is economic to bring this project forward to align with the retirement of the 33kV gas filled cables.

The main consideration driving the staged retirement of the 11kV switchgear at Darlinghurst Zone Substation is the combined contribution of the 33kV gas cables and the switchgear to unserved energy.

17.3 Options

The options considered as part of Ausgrid's planning process for retiring the substation, switchgear and cables were:

1. Single-staged retirement by transferring of all 11kV load to adjacent zones.
2. Multi-staged retirement by transferring half of 11kV load to adjacent zones at different stages.
3. Replacement like-for-like on the same site with similar cable routes.
4. Replacement by building on a new site with similar cable routes.
5. Consideration of demand management.

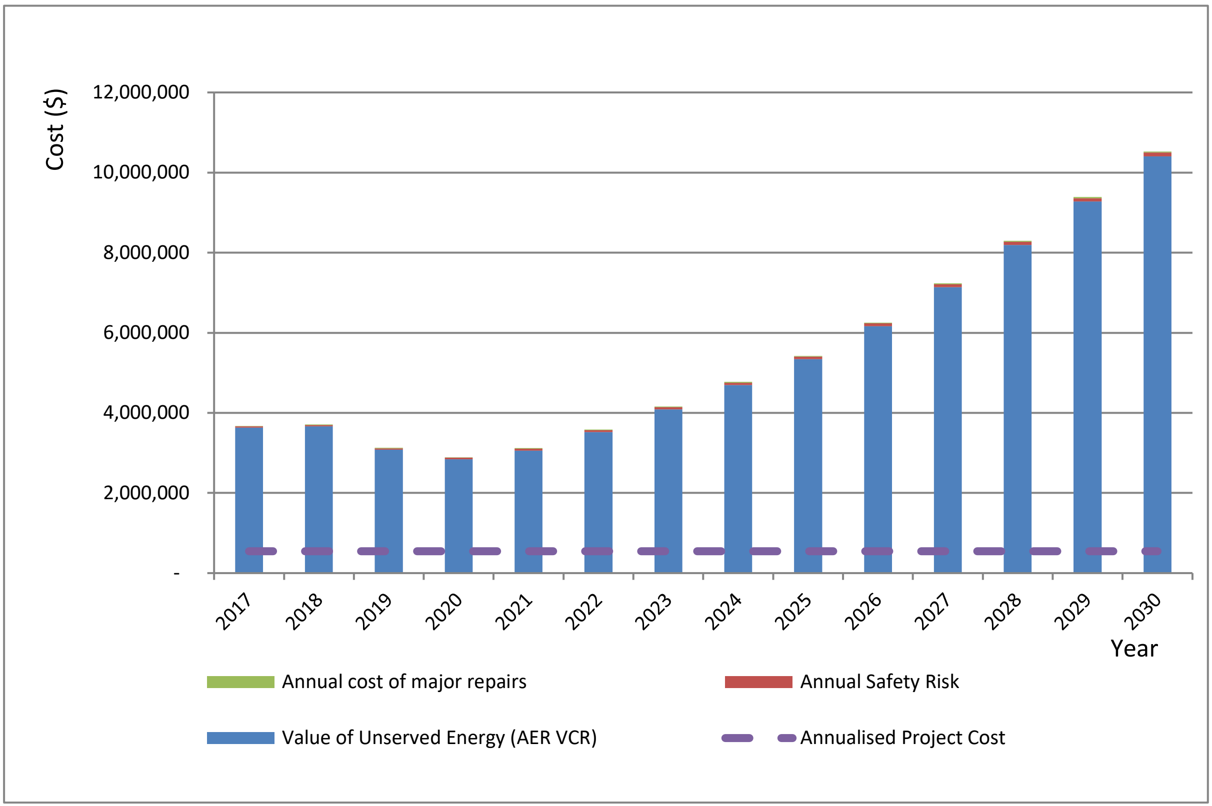
There is sufficient capacity in the adjacent Paddington, Campbell St and Surry Hills Zone Substations to implement options 1 and 2. It was found that Options 3 and 4 posed practical and economic risks because of the congested nature of the Darlinghurst area and the limited size of the existing site. Option 5 was determined to have no effect on project timing. Based on economic, technical and strategic analysis Option 2 was adopted.

This project is consistent with the overall area planning strategy.

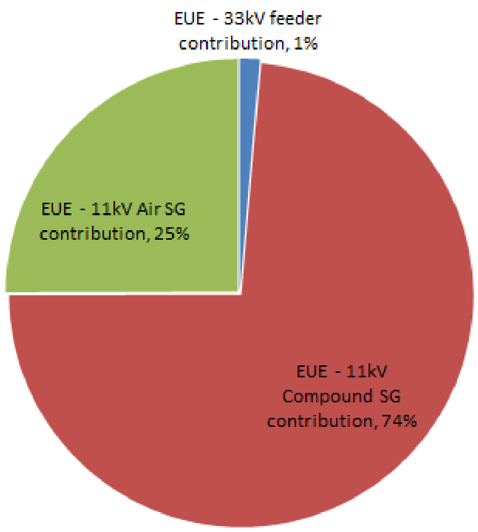
17.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date of 2018 as illustrated in the cost and benefit graph below.

Figure 30. Total risk cost versus project deferral benefit



The pie diagram below shows the EUE contribution by each asset category in FY2017/18.



Based on the EUE findings and feedback regarding asset condition, the majority of network risk is contributed by 11kV compound switchgear, and they should be addressed first, rather than address all the network risks all at once, as the likelihood of power outages caused by 11kV air-insulated switchgear and 33kV gas-pressured insulated cables are relatively low.

Hence, it is recommended that Option 2 – Multi staged retirement of Darlinghurst ZS is the preferred option:

> ***Stage 1*** – address the imminent need of retiring the 11kV compound switchgear in poor condition by FY 2020/21, which removes approximately 70-75% of the total network risk at minimum cost;
>
> ***Stage 2*** - should address the future needs in relation to the asset condition of the remaining 33kV gas pressure cables and remaining 11kV air-insulated switchgear post 2025, and other network uncertainties, which contributes to approximately 25 – 30% of the total network risk

The timing is also driven by the need to coordinate the work with the replacement of the other assets as described above while maintaining the required levels of reliability to customers. Deliverability, resource availability and cash flow smoothing are other factors that have defined the practical timing to complete the project as 2022.

Construction work for Stage 1 will start in 2018 and end in 2022.

17.5 Demand Management

An analysis of non-network options considered how demand management could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative. The cost benefit assessment has shown that non-network alternatives were not found to be cost effective.

Note that at this early stage there is little or no specific information known about actual non-network options available in the area, so assumptions are made about the likely scale of demand reductions possible and the estimated costs. These assumptions are based upon previous experience with delivery of demand management projects, submissions to non-network options reports from non-network solutions providers and lessons learned from demand management trials by Ausgrid and others.

As part of the Rules requirements, a RIT-D will be conducted on this project, and a NNOR will be published as part of the demand management engagement process. This will inform interested parties of the opportunity identified, and invite submissions from non-network proponents. Where the RIT-D process or any consequent tender for non-network solutions indicates that a modified non-network scope of work offers an improved cost benefit outcome, the selected solution to the need will be modified accordingly.

17.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project is outlined in the table below.

Table 16. Project cash flow ($m, real FY19)

	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
	0.4	0.4	2.9	0.02*	-	-	-
	-	-	-	-	-	-	13.6**

* This project is for Stage 1 of Darlinghurst 11kV switchgear retirement.

** This project is for Stage 2 of Darlinghurst 11kV switchgear retirement

18 PROJECT 16 - RIVERWOOD

18.1 Project description

The project is to replace the existing 11kV switchgear in the Riverwood 33/11kV Zone Substation in the St George Area of Ausgrid's network. The compound-insulated switchgear is nearing the end of its life, and is considered to pose a risk to reliability of supply in that zone. It is planned to replace the switchgear by building a new switch room on an adjacent site. We anticipate that work will need to start in 2023 to achieve a completion date of 2027.

The total project cost for the switchgear replacement in the Riverwood Zone Substation is $10.1 million of which $2.1 million is forecast to be incurred in the 2019-24 period.

Figure 31. Riverwood Zone Substation

18.2 Need

Riverwood 33/11kV Zone Substation was commissioned in 1966. It is equipped with 11kV compound-insulated switchgear which is approaching the end of its service life and has been prioritised in 2017 for replacement within 5 to 10 years.

The main consideration driving the replacement of the 11kV switchgear at Riverwood Zone Substation is its contribution to expected unserved energy.

18.3 Options

The options considered as part of Ausgrid's planning process for the replacement of the 11kV switchgear were:

1. Retirement and decommissioning of Riverwood Zone Substation by transferring of all load to the adjacent Hurstville North Zone, requiring installation of an additional transformer and associated 11kV switchgear at Hurstville North.
2. Replacement of the 11kV switchgear in a staged manner in the existing switchroom at Riverwood zone, requiring temporary transfer of some load to Hurstville North zone.
3. Replacement of switchgear at Riverwood zone by building a new switchroom on a site that is adjacent to the existing site.

4. Consideration of demand management.

Option 1 is the most expensive. Option 3 was determined to have a comparable cost to Option 2, but it would be simpler and involve less risk. Option 4 would have no impact on the timing of the project. Hence Option 3, replacement within a new switchroom on an adjacent site was selected as the preferred and most cost effective network option.

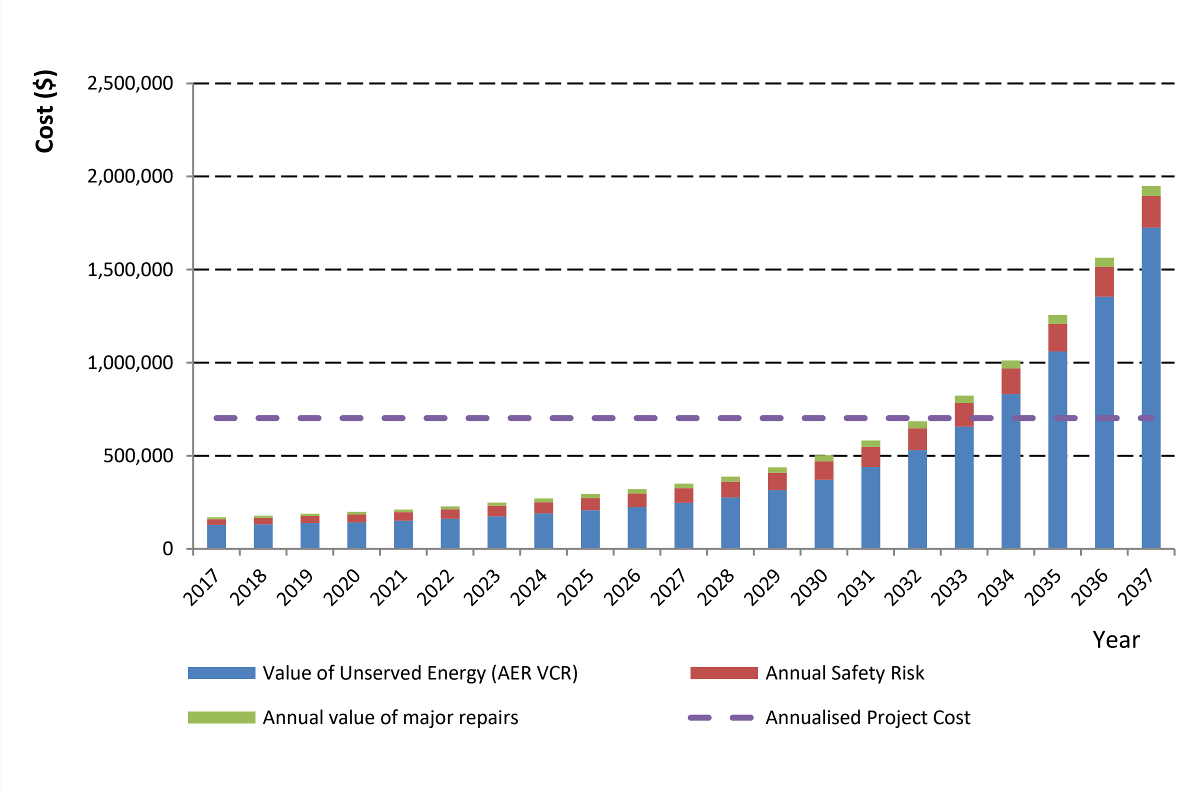
This option also provides an opportunity to address a number of secondary issues, including the condition of the roof of the existing building.

This project was determined to be consistent with the overall planning strategy for the St George Area.

18.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date of 2032 as illustrated in the cost and benefit graph below.

Figure 32. Total risk cost versus project deferral benefit



Based on Ausgrid's asset prioritisation process, the recommended replacement of the 11kV switchgear at Riverwood zone is 5-10 years. Hence, the need date considered for replacement is 2027, as determined by asset conditions, rather than 2032, as determined by cost benefit analysis.

We currently forecast that construction work will be required to start in 2023 to meet the 2027 need date.

18.5 Demand Management

The timing for this project is not driven by the result of a cost benefit analysis, but principally by other issues. Consequently, the demand reduction required to change the timing of this investment is the entire load to allow the retirement of the switchgear. A preliminary deferral analysis determined that this is not cost effective.

As part of the Rules requirements, a RIT-D will be conducted on this project, and a NNOR will be published as part of the demand management engagement process. This will inform interested parties of the opportunity identified, and invite submissions from non-network proponents. If during the consultation process a non-network option is found to offer a cost effective alternative to the preferred network option, the selected solution to the need will be modified accordingly.

18.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project is outlined in the table below.

Table 17. Project cash flow ($m, real FY19)

	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network Option	-	-	-	-	0.5	1.6	7.9

19 PROJECT 17 - MILPERRA

19.1 Project description

The project is to replace the existing 11kV switchgear at Milperra zone, which is supplied from the TransGrid owned Sydney South BSP. Milperra is in the Canterbury Bankstown region of Ausgrid's network and comprises both compound insulated and air insulated switchboard. The compound insulated switchgear is nearing the end of its life. The project involves replacement of compound insulated 11kV switchgear in a new switchroom on the existing Milperra zone site by 2027. The total project cost is $9.0 million of which $1.2 million is forecast to be incurred in the 2019-24 period.

Figure 33. Milperra Zone Substation

19.2 Need

Milperra 132/11kV Zone Substation was commissioned in 1966 and is supplied via two 132kV feeders from TransGrid owned Sydney South BSP.

The Milperra zone comprises both air and compound insulated 11kV switchgear which is aged around 51 years, and has been assessed as being in a poor condition, that has resulted in its prioritisation for retirement. Based on Ausgrid's asset prioritisation process, the compound-insulated 11kV switchgear at Milperra Zone Substation (Group 1) was given the highest priority for retirement and recommended for replacement within five to 10 years.

The main consideration driving the replacement of the 11kV switchgear at Milperra zone is its contribution to expected unserved energy.

19.3 Options

We examined the following options as part of Ausgrid's planning process:

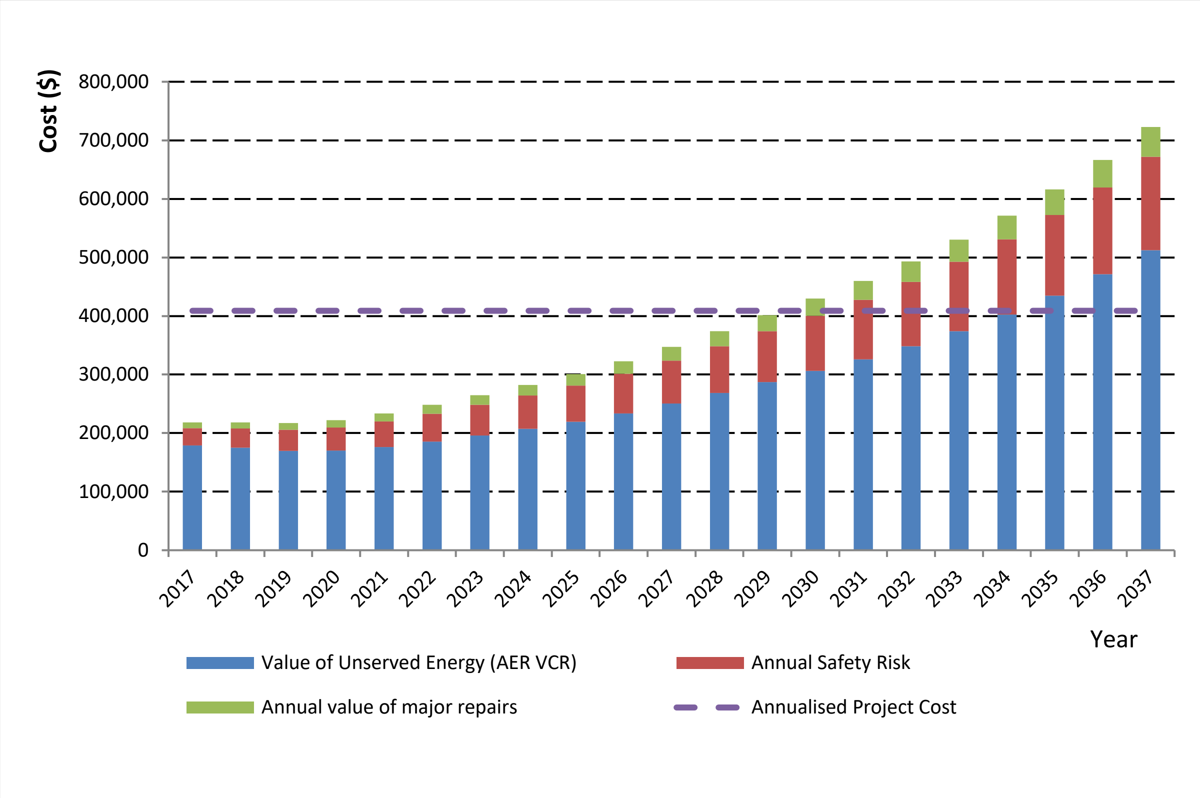
1. Replacement of 11kV compound insulated switchgear equipment in a new switchroom at Milperra Zone Substation.
2. Retirement of 11kV compound insulated switchgear equipment by transferring load to Revesby Zone Substation. This will involve installation of an additional transformer and associated 11kV switchgear at Revesby zone.
3. Consideration of demand management.

The preferred and most cost effective network solution is Option 1, namely to replace 11kV switchgear in a new switchroom within the current site.

19.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date of 2030 as illustrated in the cost and benefit graph below.

Figure 34. Total risk cost versus project deferral benefit



Based on Ausgrid's asset prioritisation process, the replacement of the 11kV switchgear at Milperra zone is recommended within five to 10 years. Hence, the need date considered for replacement is 2027, rather than 2030, subject to review annually.

We forecast that construction work will start in 2023 and end in 2027.

19.5 Demand Management

The timing for this project is not driven by the result of a cost benefit analysis, but principally by other issues. Consequently, the demand reduction required to change the timing of this investment is the entire load to allow the retirement of the switchgear. A preliminary deferral analysis determined that this is not cost effective.

As part of the Rules requirements, a RIT-D will be conducted on this project, and a NNOR will be published as part of the demand management engagement process. This will inform interested parties of the opportunity identified, and invite submissions from non-network proponents. If during the consultation process a non-network option is found to offer a cost effective alternative to the preferred network option, the selected solution to the need will be modified accordingly.

19.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project is outlined in the table below.

Table 18. Project cash flow ($m, real FY19)

	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network Option	-	-	-	-	0.2	1.1	7.8

20 PROJECT 18 - PYMBLE

20.1 Project description

The project is to replace the existing 11kV switchgear at Pymble 33/11kV Zone Substation in the Upper North Shore region of Ausgrid's network. The substation comprises both compound insulated and air-insulated switchgear that are both nearing their end of life. Based on our cost-benefit analysis the asset should be replaced by 2030. However, based on Ausgrid's asset prioritisation process, the condition issues of the 11kV switchgear at Pymble Zone Substation need to be addressed within five to 10 years (i.e. by 2027). The options analysis suggests that the asset should be replaced with modern equivalent switchgear. There is limited available space on the site, and the work will require the installation of temporary equipment to allow the progressive replacement of the switchgear. The total project cost is $11.9 million of which $1.2 million is forecast to be incurred in the 2019-24 period.

Figure 35. Pymble Zone Substation

20.2 Need

Pymble 33/11kV Zone Substation was commissioned in 1964 and is supplied by three cables from Kuringai Subtransmission Station that are directly connected to three transformers at Pymble Zone.

Pymble Zone Substation comprises two groups of double busbar 11kV switchgear: one group with compound insulated Westinghouse HQ switchgear and the second group with air insulated OLX 11kV switchgear with vacuum circuit breakers.

Based on Ausgrid's asset prioritisation process, the poor 11kV switchgear condition issues need to be addressed in the next five to 10 year period (i.e. by 2027).

There are no condition issues associated with 33kV cables supplying Pymble Zone Substation.

The main consideration driving the replacement of the 11kV switchgear at Pymble Zone Substationis its contribution to expected unserved energy.

20.3 Options

We examined the following options as part of Ausgrid's planning process:

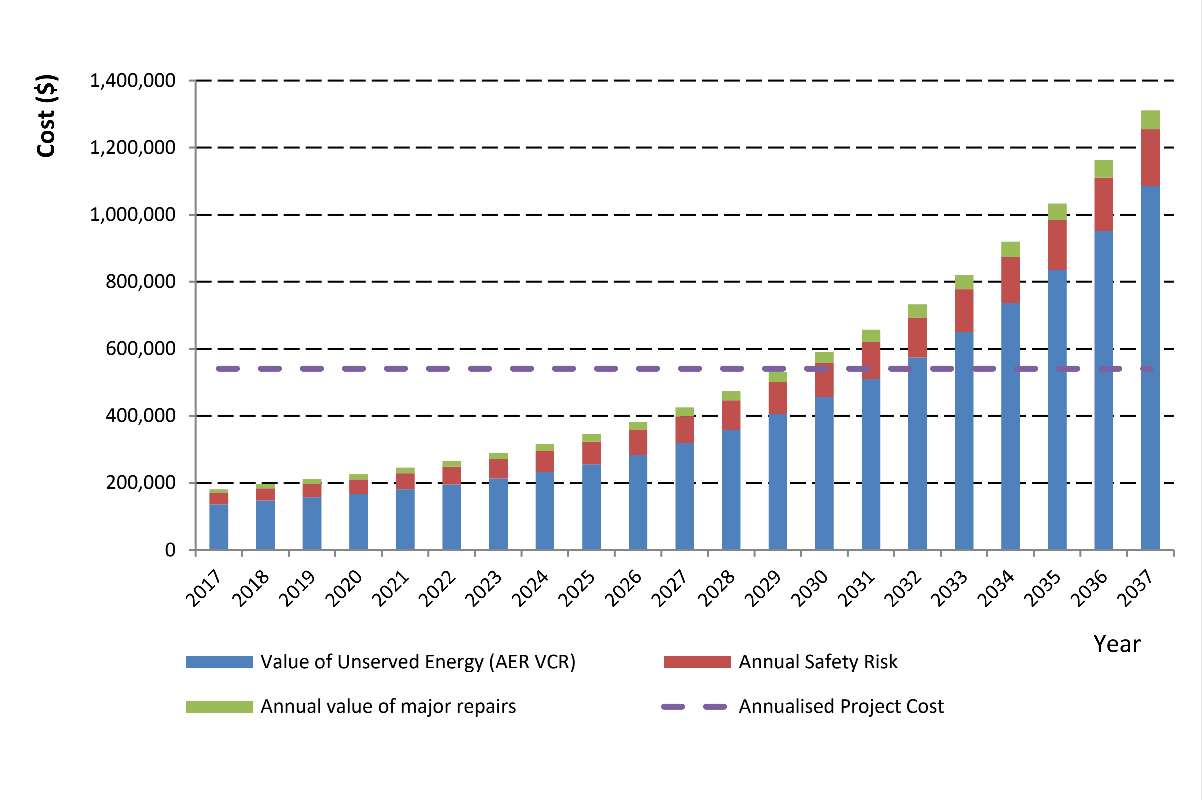
1. Replacement of 11kV switchgear at Pymble Zone Substation by installing switchgear in an available space within the existing building to facilitate progressive replacement.
2. Retirement of Pymble Zone Substation via 11kV load transfers to surrounding zones.
3. Consideration of demand management.

The preferred network solution to resolve issues at Pymble Zone Substation is Option 1, namely to replace 11kV switchgear within the existing switchroom by utilising the space provided for the future third group 11kV switchgear. This project does not involve or resolve other issues in the area.

20.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date of 2030 as illustrated in the cost and benefit graph below.

Figure 36. Total risk cost versus project deferral benefit



Based on Ausgrid's asset prioritisation process, the replacement of the 11kV switchgear at Pymble Zone Substationis recommended within 5 to 10 years. Hence, the need date considered for replacement is 2027, rather than 2030, subject to review annually.

We anticipate that construction work will start in 2023 and end in 2027.

20.5 Demand Management

The timing for this project is not driven by the result of a cost benefit analysis, but principally by other issues. Consequently, the demand reduction required to change the timing of this investment is the entire load to allow the retirement of the switchgear. A preliminary deferral analysis determined that this is not cost effective.

As part of the Rules requirements, a RIT-D will be conducted on this project, and a NNOR will be published as part of the demand management engagement process. This will inform interested parties of the opportunity identified, and invite submissions from non-network proponents. If during the consultation process a non-network option is found to offer a cost effective alternative to the preferred network option, the selected solution to the need will be modified accordingly.

20.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project is outlined in the table below.

Table 19. Project cash flow ($m, real FY19)

	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network Option	-	-	-	-	0.1	1.1	10.8

21 PROJECT 19 - LEIGHTONFIELD

21.1 Project description

The project is to replace the existing 11kV switchgear at Leightonfield, which is a "stand-alone" 33kV Zone Substation, supplied via Endeavour Energy's network from its Guildford Subtransmission Substation. Leightonfield is in the Canterbury Bankstown region of Ausgrid's network. The compound insulated switchgear is nearing the end of its life, and some of the 33kV equipment does not comply with Ausgrid's safety standards. The work is to take place in two stages, the first of which addresses medium term issues with three 11kV switchgear panels. It is committed for completion in June 2018. The second stage involves rebuilding the zone substation, including the 11kV switchgear, 33kV switchgear and busbar and adding voltage-control plant. The total project cost for stage 2 is $8.4 million.

Figure 37. Leightonfield Zone Substation

21.2 Need

Leightonfield 33/11kV Zone Substation is supplied via two 33kV feeders from Endeavour Energy's Guilford Subtransmission Substation. Leightonfield Zone Substation was commissioned in 1962.

The following issues have been identified at Leightonfield Zone Substation:

- 33kV circuit breakers are of the bulk oil type and are at the end of their service lives
- 11kV compound insulated switchgear is approaching the end of its service life and is prioritised for replacement
- 33kV busbar at Leightonfield Zone Substation is not compliant with minimum height requirements
- Transformers Tx2 and Tx3 at Leightonfield are in poor condition.

The 11kV circuit breakers Panel 1-4 of Reyrolle "C" type were in very poor condition and have already been decommissioned by distributing the loads to the remaining panels at Leightonfield Zone Substation. The 11kV oil filled circuit breakers panel 8-17 are being replaced with vacuum circuit breaker trucks. The 11kV circuit breakers Panels 5-7 of

Westinghouse “B” series type currently do not have compatible vacuum circuit breaker truck equivalents and these circuit breakers cannot be replaced.

Transformers Tx2 and Tx3 are in poor condition and are planned to be replaced with ex-Maitland Central Zone transformers. To mitigate the remaining 11kV switchgear risk, there is already a committed project to replace the three panels of the switchgear and the total Zone capacity is to be reduced from three to two transformers.

The last stage of the project is to provide a long-term solution to address the remaining switchgear and 33kV busbar condition issues. On completion the existing Substation will be decommissioned.

The main consideration driving the replacement of the 11kV switchgear at Leightonfield Zone Substation is the contribution to expected unserved energy.

21.3 Options

We examined the following options as part of Ausgrid’s planning process:

1. Replacement of 11kV switchgear equipment within the existing Leightonfield site (brownfield).
2. Replacement of 11kV switchgear on a new site adjacent to existing Leightonfield Zone Substation (greenfield).
3. Construct a new 33/11kV Leightonfield Zone Substation.
4. Consideration of demand management.

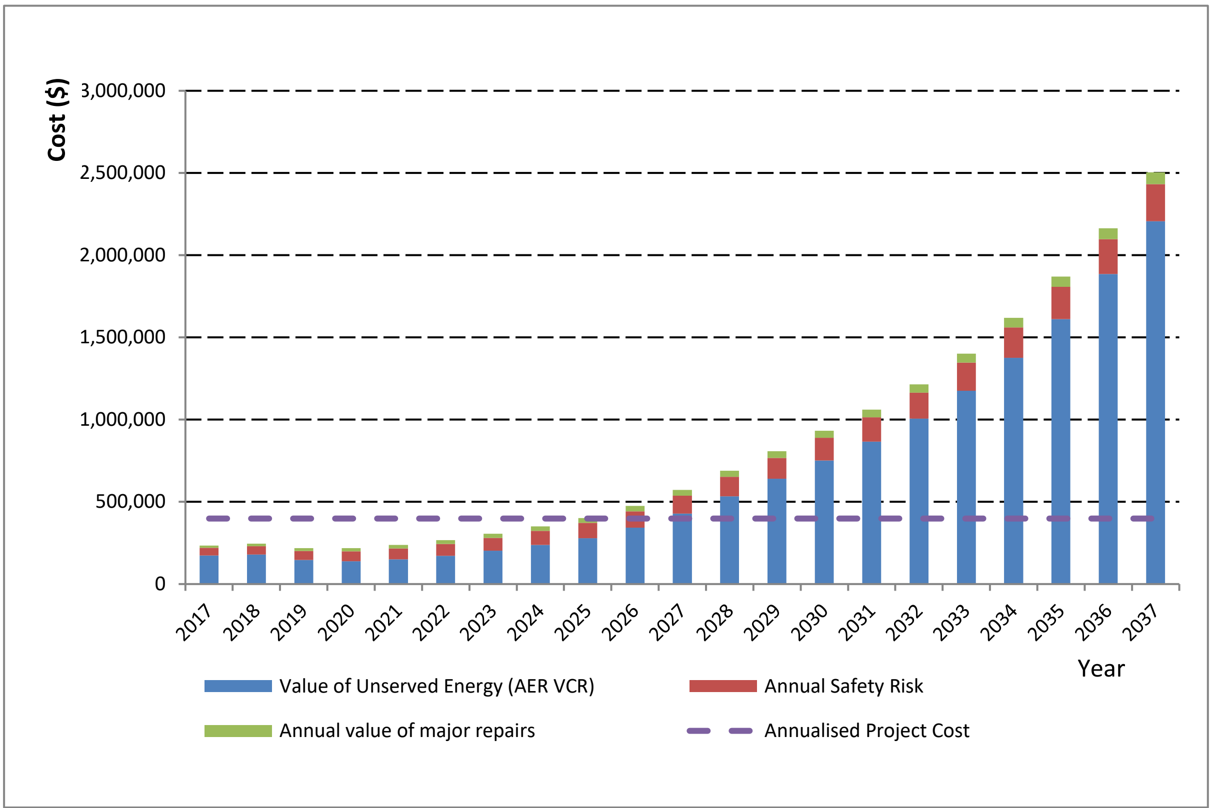
The green field options are the only feasible options as the existing site cannot accommodate the new switchgear arrangement required. Option 2 is most cost effective and it meets future needs of Leightonfield Zone Substation. As such, the preferred network solution is Option 2, namely to replace 11kV switchgear on a new site.

This project does not involve or resolve other issues in the area, such as the condition of the 33kV busbar and switchgear.

21.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date of 2025 as illustrated in the cost and benefit graph below. Based on deliverability and resource availability, the optimum delivery date of the preferred network solution is 2025.

Figure 38. *Total risk cost versus project deferral benefit*



21.5 Demand Management

An analysis of non-network options considered how demand management could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative.

The cost benefit assessment has shown that the non-network option is able to efficiently reduce the estimated unserved energy at risk in advance of the completion date and a deferral of the preferred network option by three years from 2025 to 2028. As such, this option is the preferred option. Details on the capital and operating expenditure impacts are found in Chapter 5 (Capital expenditure) and Chapter 6 (Operating expenditure) of the regulatory proposal.

Note that at this early stage there is little or no specific information known about actual non-network options available in the area, so assumptions are made about the likely scale of demand reductions possible and estimated costs. These assumptions are based upon previous experience with delivery of demand management projects, submissions to non-network options reports from non-network solution providers and lessons learned from demand management trials by Ausgrid and others.

As part of the Rules requirements, a RIT-D will be conducted on this project, and a NNOR will be published as part of the demand management engagement process. This will inform interested parties of the opportunity identified, and invite submissions from non-network proponents. Where the RIT-D process or any consequent tender for non-network solutions indicates that a modified non-network scope of work offers an improved cost benefit outcome, the selected solution to the need will be modified accordingly.

We forecast that construction work for the preferred option (including demand management) will start in 2024/25 for completion by 2028.

21.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project, including both the network option and the preferred option including demand management, are outlined in the table below.

Table 20. Project cash flow ($m, real FY19)

	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network Option	-	-	-	0.06	0.8	2.1	4.9
DM Option (Preferred)	-	-	-	-	-	-	8.4

22 PROJECT 20 – ST IVES

22.1 Project description

The project is to replace the 11kV switchgear at St Ives Zone Substation in the Upper North Shore Area of Ausgrid's network. The air insulated switchgear is nearing the end of its life, and based on our assessment of asset condition, the asset should be replaced by 2027. The option analysis suggests that the asset should be replaced with modern equivalent switchgear. The total project cost is $15.7 million.

Figure 39. St Ives Zone Substation

22.2 Need

St Ives 33/11kV Zone Substation was commissioned in 1969 and is supplied by three cables from Kuringai Subtransmission Station. These cables are directly connected to three transformers at St Ives Zone.

St Ives Zone Substation comprises of two groups of double busbar air insulated 11kV switchgear with vacuum circuit breakers. The 11kV switchgear has been assessed as being in a degraded condition and has been prioritised for retirement within 10 to 20 years. It is recommended for retirement in 2026-2027.

There are no condition issues associated with 33kV cables supplying St Ives Zone Substation.

The main consideration driving the replacement of the 11kV switchgear at St Ives Zone Substation is its contribution to expected unserved energy.

22.3 Options

We examined the following options as part of Ausgrid's planning process:

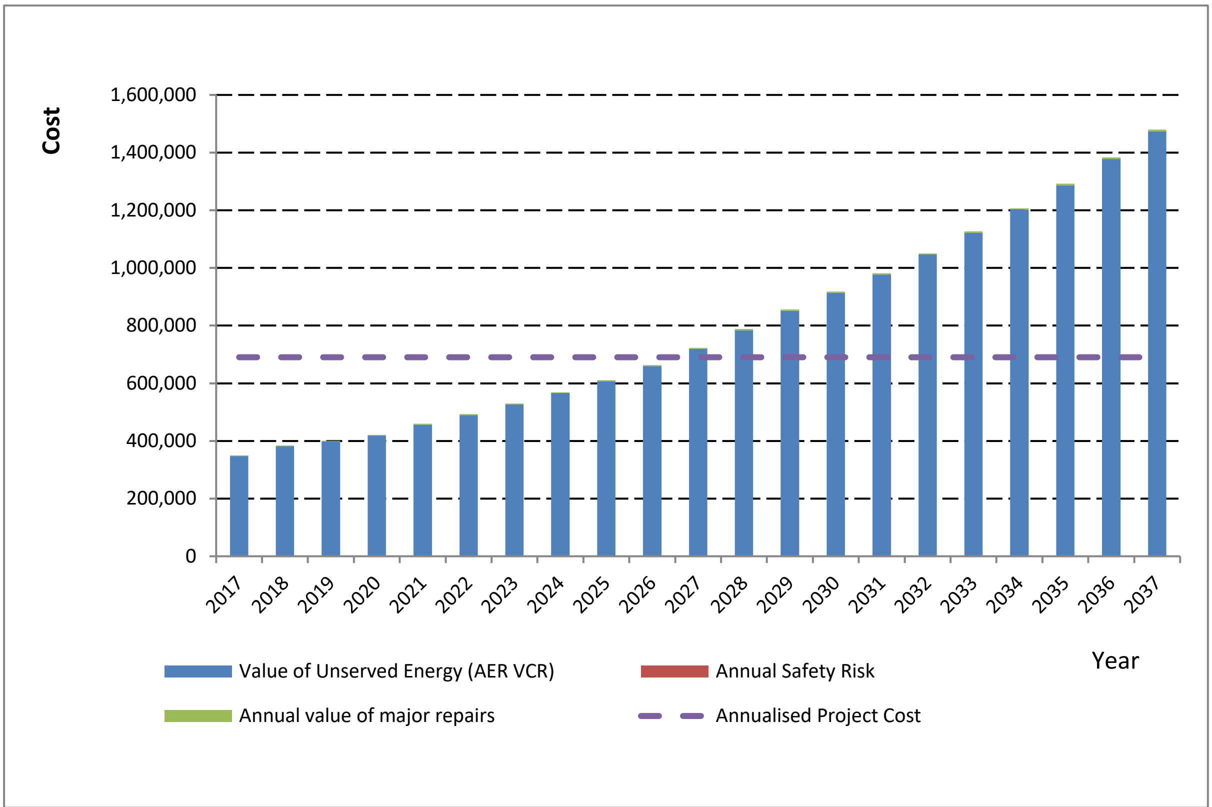
1. Replacement of 11kV switchgear at St Ives Zone Substation in spare space within the existing switchroom.
2. Retirement of St Ives Zone Substation via 11kV load transfers to surrounding zones.
3. Consideration of demand management.

The preferred network solution to resolve issues at St Ives Zone Substation is Option 1, namely to replace 11kV switchgear within the existing switchroom by utilising the space allocated for the future third group 11kV switchgear. This project does not involve or resolve other issues in the area.

22.4 Timing

We used cost benefit analysis, which includes the estimated cost of unserved energy due to unreliability attributable to all the assets to be replaced, to identify a break-even replacement date of 2027 as illustrated in the cost and benefit graph below. The optimum delivery date of the preferred network solution is 2027.

Figure 40. Total risk cost versus project deferral benefit



22.5 Demand Management

An analysis of non-network options considered how demand management could defer the timing of the preferred network solution and whether the estimated unserved energy at risk could be cost effectively reduced. The analysis used the same unserved energy model and cost benefit assessment developed to assess network options to compare the net present value of the preferred network option against the non-network alternative.

The cost benefit assessment has shown that the non-network option is able to efficiently reduce the estimated unserved energy at risk in advance of the completion date and a deferral of the preferred network option by three years from 2027 to 2030. As such, this option is the preferred option. Details on the capital and operating expenditure impacts are found in Chapter 5 (Capital expenditure) and Chapter 6 (Operating expenditure) of the regulatory proposal.

Note that at this early stage there is little or no specific information known about actual non-network options available in the area, so assumptions are made about the likely scale of demand reductions possible and the estimated costs. These assumptions are based upon previous experience with delivery of demand management projects, submissions to non-network options reports from non-network solution providers and lessons learned from demand management trials by Ausgrid and others.

As part of the Rules requirements, a RIT-D will be conducted on this project, and a NNOR will be published as part of the demand management engagement process. This will inform interested parties of the opportunity identified, and invite submissions from non-network proponents. If during the consultation process a non-network option is found to offer a cost effective alternative to the preferred network option, the selected solution to the need will be modified accordingly.

We forecast that construction work for the preferred option (including demand management) will start in 2026/27 for completion by 2030/31.

22.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the BPC tool outlined in Attachment 5.03.

The cash flow for the project, including both the network option and the preferred option including demand management, are outlined in the table below.

Table 21. Project cash flow ($m, real FY19)

	Previous years	2019/20	202/21	2021/22	2022/23	2023/24	Later years
Network Option	-	-	-	-	0.1	1.2	13.3
DM Option (preferred)	-	-	-	-	-	-	15.7