ACIL ALLEN

26 June 2023

Report to Infrastructure Victoria

Economic assessment of adapting electricity distribution networks to climate change

Final report

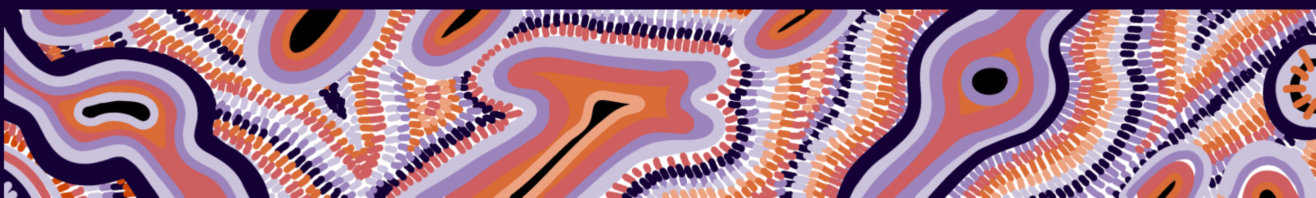
About ACIL Allen

ACIL Allen is a leading independent economics, policy and strategy advisory firm, dedicated to helping clients solve complex issues.

Our purpose is to help clients make informed decisions about complex economic and public policy issues.

Our vision is to be Australia's most trusted economics, policy and strategy advisory firm. We are committed and passionate about providing rigorous independent advice that contributes to a better world.

ACIL Allen acknowledges Aboriginal and Torres Strait Islander peoples as the Traditional Custodians of the land and its waters. We pay our respects to Elders, past and present, and to the youth, for the future. We extend this to all Aboriginal and Torres Strait Islander peoples reading this report.



Goomup, by Jarni McGuire

Contents

Figures

Contents

Abbreviations

ABS	Australian Bureau of Statistics
AER	Australian Energy Regulator
BCR	Benefit-cost ratio
CBA	Cost-benefit analysis
HV	High voltage
km	kilometre
kV	kiloVolt
kVA	kiloVolt-Amp
kW	kiloWatt
kWh	kiloWatt-hour
LV	Low voltage
mm	millimetre
MVA	MegaVolt-Amp
MWh	MegaWatt-hour
NPV	Net present value
RBA	Reserve Bank of Australia
RCP	Representative Concentration Pathway
SAPS	Stand-alone power system
VCR	Value of Customer Reliability

Executive summary

Climate change is increasing the impact of weather on infrastructure, and this impact will continue to grow over time. Climate change amplifies a range of hazards including extreme heat, bushfires, floods and storms. For example, the 2019-20 Black Summer bushfires caused widespread damage to critical infrastructure, with wide-ranging impacts on communities and essential services. Thirty-eight towns lost communication, mostly caused by power outages, and impassable roads cut access to 17 of these towns.[i]

Infrastructure Victoria is assessing the risks and opportunities of adapting the state's infrastructure to climate change, and seeking to identify priority adaptation measures to improve the climate resilience of infrastructure. This report supports this wider project by examining the economic case for appropriate investment to mitigate the effects of climate change on electricity distribution networks. It sits alongside a study examining the economic case for adaptation of road infrastructure.

Electricity distribution networks transport electricity from the high voltage transmission network to end customers, and typically do so using overhead infrastructure. This creates a risk of disruptions to supply ('outages') due to weather-related damage. Extreme wind events can result in many thousands of customers experiencing outages at the same time, which stretches the resources available to restore power and can result in some customers experiencing very long periods without power. As the severity and frequency of extreme wind events is likely to increase over time due to climate change, the risk of these outages is also likely to increase.

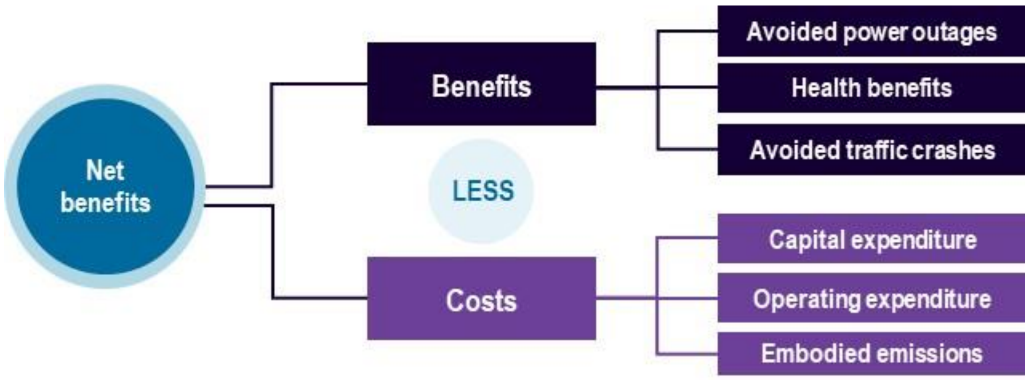
Increasing electricity distribution resilience and adapting this infrastructure to expected climate impacts is an increasing focus of governments and the electricity industry. For example, the Victorian Government commissioned an *Electricity Distribution Networks Resilience Review* to improve the resilience of these networks following a major storm and widespread power outages in June 2021.[ii] Similarly Energy Networks Australia has developed guidance to help its electricity distribution network members manage the growing effects of climate change.[iii]

Reflecting the importance of electricity distribution adaptation, Infrastructure Victoria engaged ACIL Allen to assess the economic costs and benefits of potential adaptation measures to address climate-related risks associated with extreme wind in the electricity distribution network.

Study approach and scenarios

We considered a range of potential adaptation measures to adapt electricity distribution networks to increasing impacts from extreme wind and short-listed four prospective measures for detailed analysis. We used a cost-benefit analysis framework to compare the costs and benefits of these short-listed adaptation measures (Figure ES 1).

Figure ES 1 Cost-benefit analysis framework for this study



Note: Health benefits stem from changes in tree canopy. Where adaptation measures allow an increase in tree canopy they will deliver health benefits to local residents by reducing local temperatures on hot days.

Source: ACIL Allen analysis

We compared the four short-listed adaptation actions to a base case to estimate the costs and benefits of these actions relative to a 'do-nothing' approach:

— The **base case**: existing overhead distribution infrastructure is replaced like-for-like incrementally as individual components reach end-of-life.

— **Undergrounding**: existing overhead distribution infrastructure is replaced with equivalent underground infrastructure at the start of the modelling period.

— **Tree replacement**: large trees that have the potential to damage overhead distribution infrastructure are removed and replaced with mature trees of a lower-growing species.

— **Grid-forming inverters**: electricity customers that install solar and battery systems are required to install 'grid-forming' inverters that are capable of operating as a stand-alone or 'islanded' system in the event of a grid outage, reducing the cost of these outages.

— **Insulated cable**: existing overhead conductors are replaced with overhead insulated cables at the start of the modelling period.

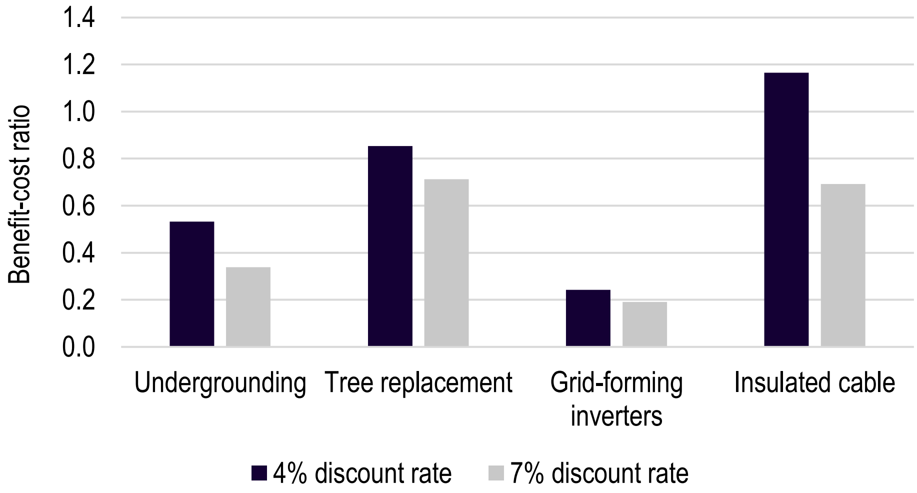
We modelled the costs and benefits of these adaptation actions on an 'exemplar' or case study consisting of a single hypothetical urban supply area serving about 1,900 customers. Reflecting the focus of this analysis on the effects of extreme wind on the distribution network, we assume that this supply area has higher than typical exposure to wind and vegetation related outages and higher than typical reliance on overhead distribution infrastructure. We further assume that climate change will drive an increase in both the severity and frequency of extreme winds events in all scenarios, with a particularly large impact on outages in the base case as no adaptation actions are in place.

Although the exemplar only represents about 1,900 hypothetical customers, our analysis indicates that over 300,000 urban customers across Victoria (about 10% of all customers) have similar exposure to outages and similar reliance on overhead distribution network infrastructure to our exemplar. These customers are located both across metropolitan Melbourne and in a range of regional towns. This means that the findings of this cost-benefit analysis are likely to be applicable across a large range of supply areas.

Results

Our analysis finds that all of the adaptation measures modelled are effective in reducing electricity outages to varying degrees and so help to adapt the distribution networks to climate-driven effects of extreme wind, but we find that only one adaptation measure – insulated cable – delivers a net societal benefit using a 4% discount rate, and no measure does so at a 7% discount rate (Figure ES 2). While the benefit-cost ratios generally do not exceed one (the level at which an investment delivers a net societal benefit), this finding reflects the specific assumptions of this study and will not necessarily be the case when considering wider factors that were not formally quantified as part of our cost-benefit analysis. In particular, formally quantifying the amenity benefits of undergrounding could significantly change the benefit-cost ratio of this measure and push its benefit-cost ratio well above one (see Figure ES 3 and the associated discussion on the next page).

Figure ES 2 Benefit-cost ratios, by scenario and discount rate



Source: ACIL Allen analysis

While the cost-benefit analysis could be interpreted as indicating that installation of insulated cable is justified at a discount rate of 4%, we consider that this result should be interpreted with caution:

— The result is sensitive to assumptions, with our sensitivity analysis showing that increasing capital cost assumptions or reducing the assumed cost of power outages results in the costs of this measure exceeding the benefits.

— Our analysis of distributional outcomes highlights difficult questions about who should pay for insulated cable investments, because the general base of electricity consumers would incur significant costs, while local residents and local electricity consumers enjoy the vast majority of the benefits.

Our sensitivity analysis indicated that the results for other adaptation measures were generally less sensitive to assumptions, with the benefit-cost ratio of undergrounding and grid-forming inverters remaining well below one under all modelled sensitivities. Tree replacement delivered a net societal benefit under some assumptions, particularly higher outage costs from extreme wind, but did not under most sensitivities analysed.

Discussion and conclusions

Examine the reliability benefits of insulated cable

Our analysis suggests that there may be merit in further investigation of the costs and benefits of using insulated cable to better adapt electricity distribution networks to the effects of climate change and reduce power outages. However, this finding is subject to some uncertainty.

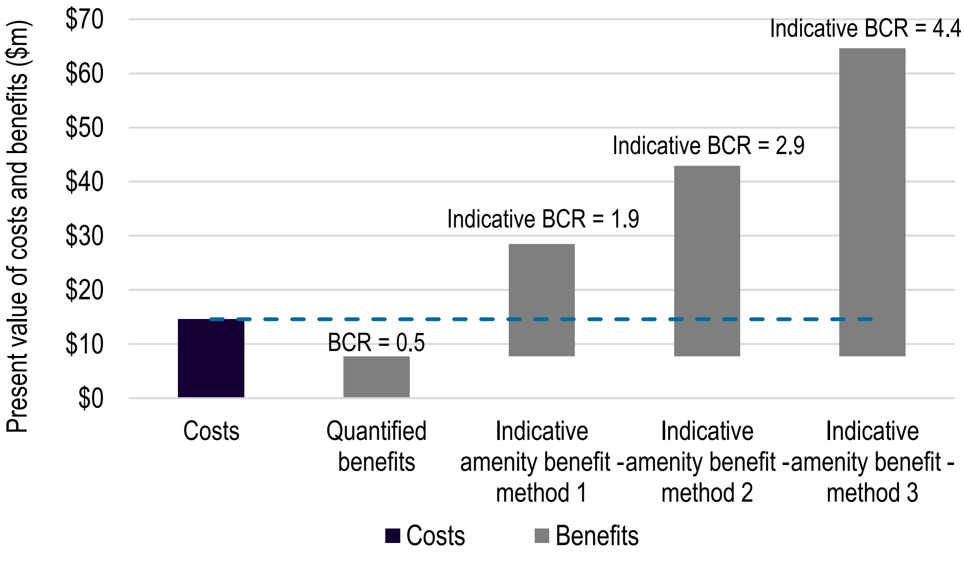
An important area of uncertainty is the effectiveness of insulated cable in reducing outages, but this uncertainty may be able to be reduced at relatively low cost. Some networks routinely use insulated cable for replacement of low voltage circuits, and this could provide conditions for a 'natural experiment' to demonstrate its reliability benefits. Comparing the reliability of network sections that have insulated cable with the rest of the network could give greater confidence on the effectiveness of insulated cable in preventing outages, which would be valuable for informing future decisions on the use of this adaptation measure.

Examine the amenity benefits of undergrounding

Our analysis finds that undergrounding is very effective in reducing outages, but that it is not a cost-effective way to reduce power outages from the effects of extreme wind for the hypothetical urban supply area modelled, even when the health benefits it can deliver through increased tree cover and reduced traffic crash costs are taken into account.

However, undergrounding may also deliver significant amenity benefits, such as improved streetscape aesthetics, reduced physical obstacles and the visual amenity of increased tree cover. We have only provided indicative quantifications of these benefits in this study, because the relevant literature is from over ten years ago and examined locations outside of Victoria. However, if benefits of a comparable size translate from earlier Western Australian and Canberran studies to Victoria, then undergrounding could offer significant net benefits, with benefit-cost ratios well in excess of one (Figure ES 3). In that case, the combined benefits of undergrounding may well justify investment, and this investment would help distribution networks adapt to climate change.

Figure ES 3 Present value of costs and benefits of undergrounding using a 4% discount rate, including indicative estimates of amenity benefits



Source: ACIL Allen analysis

Undergrounding is a complex exercise that delivers benefits to multiple groups in societies – including home-owners, businesses, visitors, local governments, electricity distribution companies and state governments – and so implementation requires cooperation across a number of these parties. This complexity, and the experience of undergrounding programs in Western Australia and South Australia, suggests that the Victorian Government would need to play a significant role to facilitate future undergrounding projects in the state.

Potential Victorian Government actions to support future undergrounding of electricity infrastructure include:

— building contemporary knowledge on the benefits of undergrounding in the Victorian context, as reliable estimates of amenity benefits are needed to support the business case for widespread undergrounding, and active Victorian Government support to build this business case will help to both unlock these amenity benefits and better adapt distribution networks to expected impacts from climate change
— working with parties that benefit from undergrounding, such as local governments (acting on behalf of home-owners and businesses) and electricity distribution network businesses
— establishing standardised processes to simplify undergrounding for both electricity network businesses and local governments.

Preparing Victorian distribution networks for the future

Our analysis assumes that the existing overhead network infrastructure is of mixed age and is replaced periodically over its expected life of 50 years. However, if network re-investment is required more urgently than we have assumed, the base case investment cost increases in present value terms and the case for investing in undergrounding or insulated cable is strengthened.

One potential driver of network re-investment is rapid growth in electricity demand that outstrips the capacity of existing network assets. While peak electricity demand growth has been muted in recent years, there is a high likelihood of significant increases in demand throughout Victoria's electricity distribution networks over coming decades from two main sources: electric vehicles and the electrification of household heating.

While the scale and speed of this demand growth is highly uncertain and hotly debated, the potential need for investment to accommodate electric vehicles and heating electrification creates an opportunity to also better adapt these networks to the effects of climate change by insulating or undergrounding power lines when reinvestment is required. Additionally, insulating or undergrounding power lines helps Victoria prepare for a hotter future under climate change, as they allow increased levels of urban vegetation that reduces the effect of extreme heat on local residents.

Lessons for other studies

ACIL Allen used a typical cost-benefit analysis framework for this analysis, and this broad framework can be applied to a range of infrastructure assessments, including the cost-effectiveness of climate change adaptation measures. For example, Infrastructure Victoria has concurrently commissioned a similar assessment of adaptation measures for road infrastructure.

We had to address a range of significant complexities and uncertainties to undertake this study, and this is likely to be common to many cost-benefit analyses of climate adaptation for infrastructure. Some particularly difficult methodological issues we have encountered in this study are summarised below.

— Climate change impacts are particularly uncertain and sensitive to assumptions on global emissions concentration pathways. This is particularly true of extreme wind due to its localised impacts, but other studies will still likely need to reflect this uncertainty through scenario and sensitivity analysis.

- Adaptation measures both mitigate the impacts of climate change and contribute to it through embodied emissions. We found embodied emissions were not large enough to be a material barrier to use of the adaptation measures we assessed, but this finding may not translate to other infrastructure assessments and so case-specific analysis is essential.
- The benefits of adaptation actions can be sensitive to the scale at which they are applied. For example, the benefit of more reliable electricity supply to transport infrastructure and other essential services will be modest if the measure is only applied narrowly but could increase significantly if it is adopted widely. This finding is likely to translate to other types of network infrastructure, such as transport and telecommunications.
- Climate adaptation measures could reduce the impact of the identified hazard (in our case, extreme wind), but cause maladaptations that exacerbate other risks to the infrastructure. We assessed that the maladaptation risk was not material for our adaptation measures, but this finding may not translate to other infrastructure assessments and so case-specific analysis is essential.
- Some cost or benefit elements are particularly uncertain and hard to estimate. In our case, important examples included amenity benefits, the number of trees that can materially impact electricity distribution infrastructure and the cost premium on grid-forming inverters. Other infrastructure assessments are likely to require similarly difficult cost or benefit estimates.

In many cases the methodologies and sources used in our study reflect costs and benefits that are specific to electricity distribution infrastructure and the effects of extreme wind, while in other cases a broad range of studies will be able to use similar approaches and assumptions. For example:

- our chosen discount rates and carbon price assumptions would be common to a broad range of cost-benefit analyses
- our analysis of health benefits from increased tree canopy would extend beyond electricity distribution infrastructure to include broader ‘green infrastructure’ such as parklands
- our analysis of power outages, network capital and operating expenditure, and embodied emissions are all specific to electricity distribution infrastructure, but this infrastructure is relatively standardised across Australia so our assumptions could be extended to studies in a large range of comparable locations – that is, a well-treed Australian urban area with primarily overhead electricity distribution infrastructure.

Study overview 1

Infrastructure Victoria is the state's independent infrastructure advisory body. It has three main functions:

— preparing a 30-year infrastructure strategy for Victoria, and reviewing and updating the 30-year strategy every 3 to 5 years[iv]
— advising the Victorian Government on specific infrastructure matters
— publishing research on infrastructure-related issues.

As part of its research program, Infrastructure Victoria is assessing the risks and opportunities of adapting the state's infrastructure to climate change. The project considers existing climate change adaptation actions in Victoria, identifies priority adaptation measures to improve the resilience of infrastructure in response to climate-related risks and evaluates the return on investment for adaptation actions.

The project phases include:

1. a high-level risk assessment of climate impacts across key infrastructure sectors including a literature review and workshops with government stakeholders
2. detailed analysis of shortlisted climate risks across Victoria and potential adaptation actions for selected asset categories (for example, roads and electricity)
3. an economic assessment of the return on investment for specific climate change adaptation measures including a quantitative and qualitative assessment of direct and indirect costs and benefits
4. a final research report.

This report is part of Phase 3, which aims to build the economic case for appropriate action and investment in climate resilient roads and electricity networks by asking the following question:

> *What is the economic return on investment for selected climate change adaptation measures in selected infrastructure sectors?*

This report focuses on climate adaptation measures for electricity distribution infrastructure (Box 1.1) by demonstrating a cost-benefit analysis of adaptation measures relevant to a selected exemplar. The outcome of this analysis will aid in identifying appropriate investments and showcase the significance of adaptation in enhancing the resilience of electricity infrastructure. It also presents a methodology which may be used by other stakeholders to assess the return on investment in climate adaptation of infrastructure. It has been written alongside a separate assessment of potential climate adaptation measures for the road network, led by Arup.

Box 1.1 Electricity distribution networks

Electricity networks transport electricity from the point it is generated to end customers. They are typically classified into two parts:

— The **transmission** network, which connects large-scale power stations to major points of supply.

— The **distribution** network, which transports power from the transmission network to end customers.

Distribution networks, rather than transmission networks, are the focus of this study.

Victoria has five distribution networks (**Figure 1.1**).

Figure 1.1 Victoria's electricity distribution networks

Source: ACIL Allen adaptation of Victorian Government, Find your energy distributor, https://www.energy.vic.gov.au/for-households/find-your-energy-distributor.

1.1 Problem definition

Climate change is increasing the impact of weather on infrastructure, and this impact will continue to grow over time. Climate change amplifies a range of hazards including extreme heat, bushfires, floods and storms. For example, the 2019-20 Black Summer bushfires caused widespread damage to critical infrastructure, with wide-ranging impacts on communities and essential services. Thirty-eight towns lost communication, mostly caused by power outages, and impassable roads cut access to 17 of these towns.[v]

As noted above, this report is part of a wider Infrastructure Victoria research project that identifies priority adaptation measures to improve the climate resilience of infrastructure. Although electricity distribution networks are significantly impacted by bushfire events (as occurred during the Black Summer bushfires) and floods, Infrastructure Victoria's work in Phase 2 of this broader research program identified the effects of extreme wind on electricity networks as a specific risk worthy of more detailed consideration. Accordingly, this study focuses on the effects of extreme wind events on electricity distribution networks.

Electricity distribution networks typically supply electricity consumers via overhead infrastructure, creating a risk of disruptions to supply ('outages') due to weather-related damage. As the severity and frequency of extreme wind events is likely to increase over time due to climate change, the risk of these outages is also likely to increase.

Extreme wind events can result in many thousands of customers experiencing outages at the same time, largely due to trees and other vegetation making contact with or falling across overhead power lines. When an extreme event affects a large number of customers at one time resources available to restore power supply are stretched, and consequently some customers can experience very long periods without power.

Recent examples of extreme wind events impacting Victorian electricity distribution networks include:

— 2 April 2008: a major windstorm hit the Melbourne metropolitan area causing power outages for about 660,000 customers
— 9-10 June 2021: heavy rainfall and strong winds affected much of the state, with particularly large effects in the Dandenong Ranges. About 330,000 customers experienced power outages, with 68,000 remaining without power for more than 72 hours
— 29-30 October 2021: strong winds hit the Melbourne metropolitan area, particularly the eastern suburbs, causing power outages for about 500,000 customers, with about 20,000 being without power for more than 72 hours.

As the likelihood and impact of geographically widespread and long duration outages increases with climate change, the economic and social costs of these outages are also likely to increase.

Increasing electricity distribution resilience and adapting this infrastructure to expected climate impacts is an increasing focus of governments and the electricity industry. For example, the Victorian Government commissioned an *Electricity Distribution Networks Resilience Review* to improve the resilience of these networks following a major storm and widespread power outages in June 2021.[vi] Similarly Energy Networks Australia has developed guidance to help its electricity distribution network members manage the growing effects of climate change.[vii] These efforts are particularly important for electricity distribution networks, as they are characterised by long-lived assets with a high level of exposure to extreme wind, and therefore to the effects of climate change.

1.2 Approach

As noted above, analysis undertaken for Infrastructure Victoria as part of Phase 2 of its infrastructure adaptation project identified extreme wind as a key risk factor for electricity networks. The strategic objective of this study is to understand the costs and benefits of early and proactive adaptation actions that can reduce the impact of extreme wind on the electricity distribution network, and therefore the economic and social cost of outages.

The study examines the costs and benefits of these actions on a de-identified hypothetical 'exemplar' or case study, consisting of a single hypothetical urban supply area serving about 1,900 customers. The exemplar is:

— de-identified, in that it refers to a non-specific geographical area
— hypothetical, as the measures analysed could be implemented in a range of locations
— an exemplar, meaning that the specific assumptions on costs and benefits applied in this study can be extended to a range of locations.

Reflecting the focus of this analysis on the effects of extreme wind on the electricity distribution networks, we assume that this supply area has:

— higher than typical exposure to wind and vegetation related outages
— higher than typical reliance on overhead distribution infrastructure.

Although the exemplar only represents about 1,900 hypothetical customers, our analysis indicates that almost 310,000 urban customers across Victoria (10% of all customers) have similar exposure to outages and similar reliance on overhead distribution network infrastructure. These customers are located across the entire Melbourne metropolitan area and in a range of regional towns, including Geelong, Ballarat, Bendigo, Morwell, Shepparton and Horsham.

This means that the findings of the economic assessment for the exemplar will have broad applicability to a large number of customers across Victoria. In other words, if our cost-benefit analysis identifies a strong case to do one or more adaptation actions for the exemplar, these actions could be considered in more detail across a large range of supply areas. Conversely, as the analysis looks at a general exemplar, analysis of similar actions in a more precisely defined location could include assumptions specific to that location, and this could lead to different results. For example, locations that serve major public facilities or critical infrastructure could likely identify higher benefits reflecting the wider impact of power outages for these facilities.

Section 2.2.2 gives more detail on the exemplar and how it was defined.

1.3 Report overview

The remainder of the report is set out as follows:

— Chapter 2 sets out the detailed methodology and assumptions used in the study.
— Chapter 3 summarises the key results of the study.
— Chapter 4 discusses some broader conclusions to inform further investigations by Infrastructure Victoria and the Victorian Government.

Detailed methodology and assumptions 2

This study uses a cost-benefit analysis (CBA) framework to assess the economic costs and benefits to the community of potential adaptation measures to address climate-related risks associated with extreme wind in the electricity distribution network, and to develop a replicable methodology for similar analyses of infrastructure adaptation actions.

Section 2.1 gives an overview of the CBA framework used in this study, while section 2.2.3 describes the adaptation measures, the exemplar and the scenarios examined. Sections 2.3 and 2.4 discuss the detailed methodology and assumptions used to estimate the major cost and benefit categories, respectively.

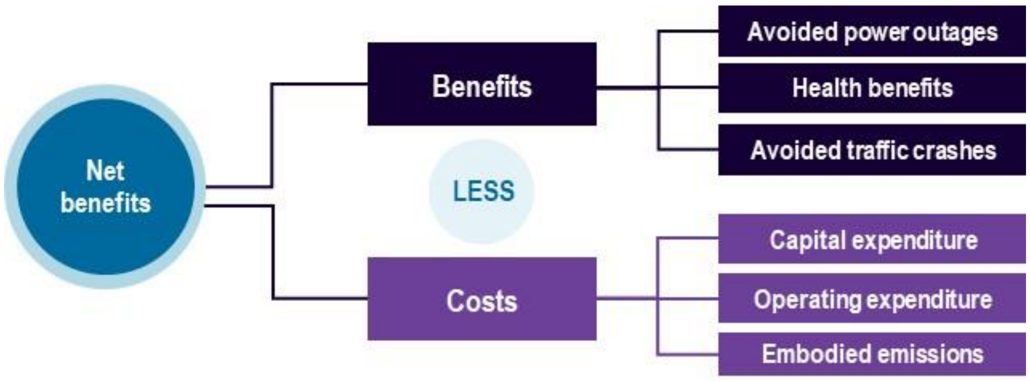
2.1 Cost-benefit analysis framework and key assumptions

CBA is a commonly used quantitative framework for logically analysing the social and economic costs and benefits of a particular policy, project or investment. The basis of a CBA is simple: for a given investment proposal, project or policy reform, a CBA compares the total projected costs of the investment or policy with the total projected benefits. This determines whether the benefits outweigh the costs, and by how much. A CBA typically assesses the economic costs and benefits associated with potential adaptation measures (an 'adaptation scenario') against those under a do-nothing scenario or 'base case', and we have adopted this approach.

2.1.1 Cost-benefit analysis framework for this study

Figure 2.1 provides an overview of the CBA framework used in this study, including the major categories of benefits and costs.

Figure 2.1 Cost-benefit analysis framework for this study



Source: ACIL Allen analysis

We analysed three major benefit categories in this study (section 2.4):

1. **Avoided power outages:** the study considers a range of adaptation actions that can reduce power outages in the electricity distribution network, particularly in the case of extreme wind, and quantifies the economic benefits of these reductions.
2. **Health benefits from increased tree canopy:** several of the adaptation actions considered in this study reduce conflict between overhead electricity infrastructure and trees, and so support an increase in the local tree canopy. This increased canopy in turn reduces local temperatures on very hot days, and so can improve the health of local residents. Conversely, one adaptation action analysed reduces tree canopy and so causes a health dis-benefit to local residents.
3. **Reduced traffic crash impacts:** one adaptation action analysed in this study, undergrounding, removes the need for above-ground power poles, and therefore the risk that vehicles will collide with these poles (though these vehicles could collide with other objects instead).

Other benefit categories are discussed qualitatively in section 2.4, but we do not formally quantify them in our CBA framework as we either found the potential impacts to be immaterial to this study, or due to limited robust evidence in the relevant literature.

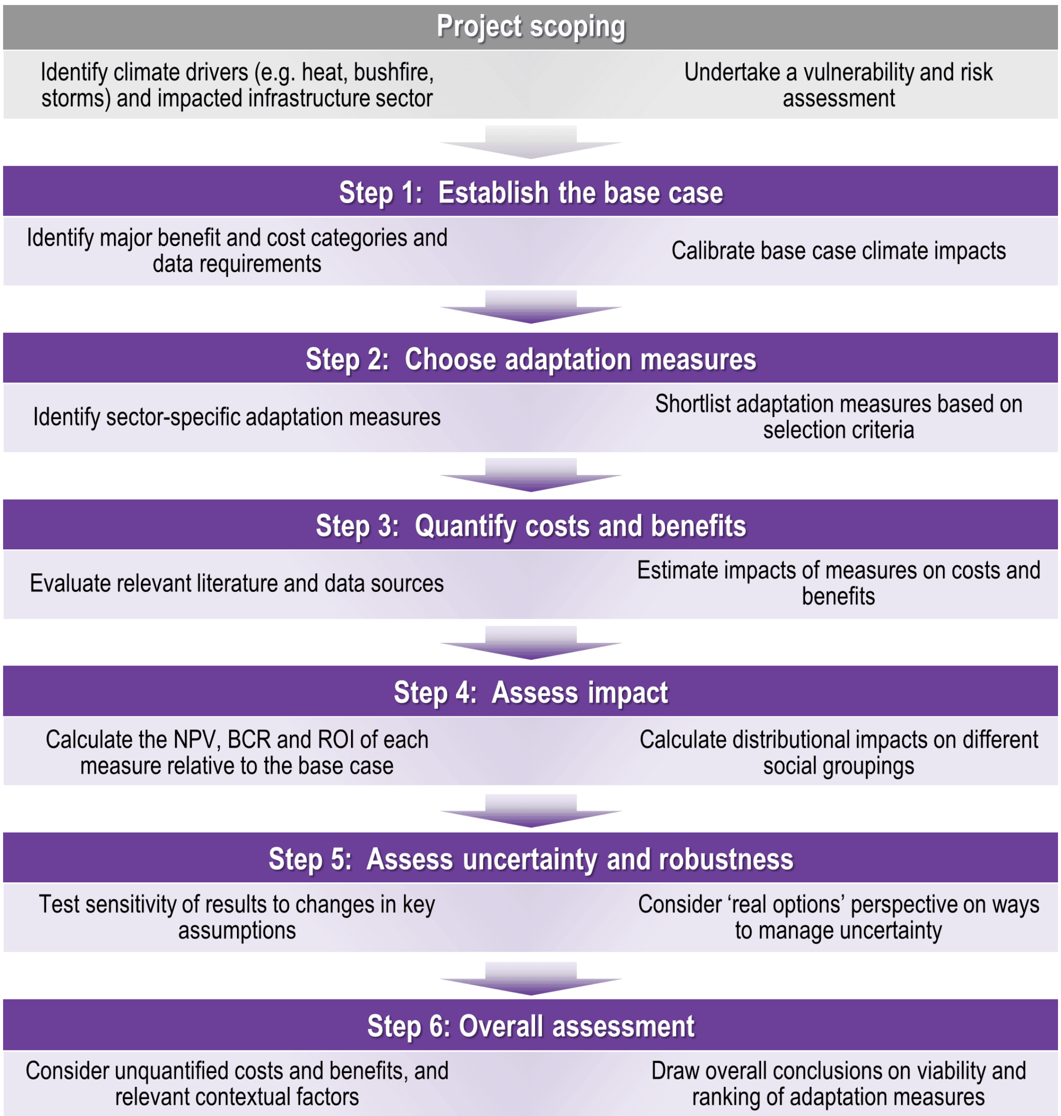
We analysed three major cost categories in this study (section 2.3):

1. **Capital expenditure:** the adaptation actions require upfront expenditure on new capital items, which represents an economic cost.
2. **Operating expenditure:** many of the adaptation actions require ongoing operational expenditure, which represents an economic cost. Some actions also reduce operating expenditure on the management of tree clearances around power lines ('vegetation management'), and this study takes these reductions into account.
3. **Embodied emissions:** many of the adaptation actions cause increased material requirements over what would otherwise be needed and so impose an economic cost on society in the form of embodied greenhouse gas emissions.

A CBA framework can be applied to a range of infrastructure assessments, including the cost-effectiveness of climate change adaptation measures. For example, as discussed in chapter 1, Infrastructure Victoria has concurrently commissioned a similar assessment of adaptation measures for road infrastructure.

Infrastructure adaptation assessments will have a number of common features and steps, stemming from the nature of the infrastructure being assessed and the specific climate risk or risks of interest. For this study we have built on assessments conducted by Infrastructure Victoria and AECOM to identify priority sectors and climate risks for analysis, and built on these prior assessments to deliver a sector- and risk-specific CBA. This combined process is described in Figure 2.2, and is likely to be illustrative of the general steps needed to prioritise and implement infrastructure adaptation assessments.

Figure 2.2 Step-wise approach to infrastructure adaptation assessments



Note: NPV = net present value; BCR = benefit-cost ratio; ROI = return on investment.
Source: Infrastructure Victoria and ACIL Allen analysis

The particular challenges of adapting a CBA framework to analyses of climate change impacts on infrastructure, and methodological lessons from this analysis, are discussed in section 4.6.

2.1.2 Treatment of climate change

The Intergovernmental Panel on Climate Change considers that it is 'unequivocal' that climate change is already occurring, and that is 'very likely' that, even under the most aggressive emissions reduction scenarios, an increase of 1°C to 1.8°C above late 19^{th} century levels will occur by the end of the 21^{st} century.[viii]

A key driver of this study is that climate change will affect the severity and frequency of extreme wind events, and this will impact electricity distribution infrastructure. For this reason, it is essential to incorporate the climate change impacts in the base case. Specifically, the severity and frequency of extreme wind events were increased in the base case to reflect outcomes under the 2019 *Victorian Climate Projections*,[ix] which in turn increases the expected cost of power outages from extreme wind in the base case (see the discussion on page 23 in section 2.4.1).

As the cost of power outages is higher in the base case than if climate change was not driving greater impacts from extreme wind, the economic benefit from adaptation measures that reduce these outages is correspondingly higher.

2.1.3 Discount rate

A key assumption in a CBA is the 'discount rate' used. The discount rate reflects that the economic behaviour of individuals, businesses and governments exhibits 'time preference', which means that they prefer to receive benefits earlier rather than later and prefer to incur costs later rather than earlier, all else being equal. This reflects, in part, the fact that the future is uncertain and so people put less weight on events the further into the future they are. To capture time preference, costs and benefits are weighted differently in a CBA depending on when they occur by discounting future costs and benefits using an annual discount rate.

The discount rate used has a very significant impact on the value placed on the benefits accumulated in the future over a long period of time as occurs, for example, in the case of investing in long-lived infrastructure with significant upfront costs but which delivers benefits over a long period of time.

There is extensive debate on the appropriate rate to discount costs and benefits in a CBA. A particular element of this debate that has arisen in the broader climate change context is whether discounting appropriately values the interests of future generations, for example from climate impacts that might be felt over centuries. For example, when the UK Government commissioned economist Nicholas Stern to review the economics of climate change in 2006, Stern adopted a low discount rate of 1.4% to appropriately value intergenerational damages.[x] In part as a result of debate over Stern's approach to discounting very long climate impacts, a declining discount rate has emerged in the economic literature as an alternative approach to avoid excessively discounting very long-term costs and benefits, including climate impacts.[xi]

We consider that declining discount rates are most appropriate for analysis over very long time periods with significant intergenerational impacts (broadly, measured in centuries). Here we are analysing measures that affect infrastructure with a long but finite lifespan, typically assessed as about 50 years, and the costs of these infrastructure choices will generally be borne by the same generations that experience the benefits. Accordingly, we have considered the Victorian Government's standard approach to discounting is appropriate for this study.

The Victorian Government's standard discount rates are:

— 4% for provision of goods and services in traditional core service delivery areas of government where the benefits are not easily translated to monetary terms
— 7% for provision of goods and services in traditional core service delivery areas of government where the benefits are more easily translated to monetary terms
— market rate for commercial investments with similar risks as the private sector.[xii]

As electricity distribution infrastructure is regulated as a natural monopoly and is not subject to typical risks associated with private sector investments in competitive markets, we consider that the 4% and 7% discount rates are most appropriate for this analysis.

2.1.4 Key cost-benefit analysis metrics

The change in costs and benefits from the base case to those under each adaptation scenario are calculated, and used to estimate the following key CBA metrics:

— A benefit-cost ratio (BCR), which is the ratio of the present value of total benefits to the present value of the total costs. A BCR of greater than one indicates that the quantifiable benefits of the policy, project or investment exceed the quantifiable costs. All things being equal, this suggests there is economic and social value in investing in the option. The reverse applies for a BCR below one.

— The net present value (NPV), which is the sum of the discounted annual net benefits (benefits less costs). A positive NPV indicates that the quantifiable benefits of the policy, project or investment exceed the quantifiable costs. All things being equal, this suggests there is economic and social value in investing in the option. The reverse applies for a negative NPV.

— A return on investment, which is the 'breakeven' discount rate at which the NPV of costs and benefits of a given adaptation measure are equal. All things being equal, a higher return on investment indicates a stronger case for investment in an adaptation measure.

2.1.5 Other over-arching assumptions

Reflecting the long-lived nature of electricity distribution infrastructure, we have analysed costs and benefits over the period to 2070 for this analysis. Given the time needed to deliver new equipment or change the way electricity distribution infrastructure is managed, we have assumed that upfront capital investments will start in 2025 and be completed by 2027.

All dollar values in the report are presented on an inflation-adjusted or 'real' basis and reflect price levels in 2023 (that is, they are presented in real 2023 dollars).

2.2 Study design

2.2.1 Study focus

As discussed in chapter 1, Infrastructure Victoria is delivering a research program that includes a high-level climate risk assessment across Victoria's regions for various government and regulated infrastructure sectors. This work short-listed a risk of damage to or degradation of electricity transmission and distribution assets due to extreme weather events, including both extreme wind and lightning.

We focused this study on the effect of extreme wind on the electricity distribution network because several factors indicate that the economic case for adaptation to address extreme wind will be stronger than for lightning:

— Extreme wind was the key driver of the largest outage events in recent Victorian history, including the April 2008 and October 2021 storms.

— The link between lightning and climate change is less clear than the link between extreme wind and climate change.

— Lightning effects are more severe in the north-eastern highlands of the state[xiii], where population is lower and so the economic and social costs of outages are lower.

This study focused on electricity distribution rather than electricity transmission (see Box 1.1) because issues in the electricity distribution network have a far greater impact on customers than issues in other parts of the supply chain. Distribution network issues typically account for about 95% of historic power outages when weighted by the outage duration and the number of customers affected.[xiv]

2.2.2 The exemplar

The decision to focus this study on extreme wind in turn led us to examine an urban 'exemplar' or case study. Extreme wind events in April 2008 and October 2021 had significant impacts in the Melbourne metropolitan region. Such urban wind storms affect a large number of customers and are have higher economic costs than extreme wind in more sparsely populated regional areas.

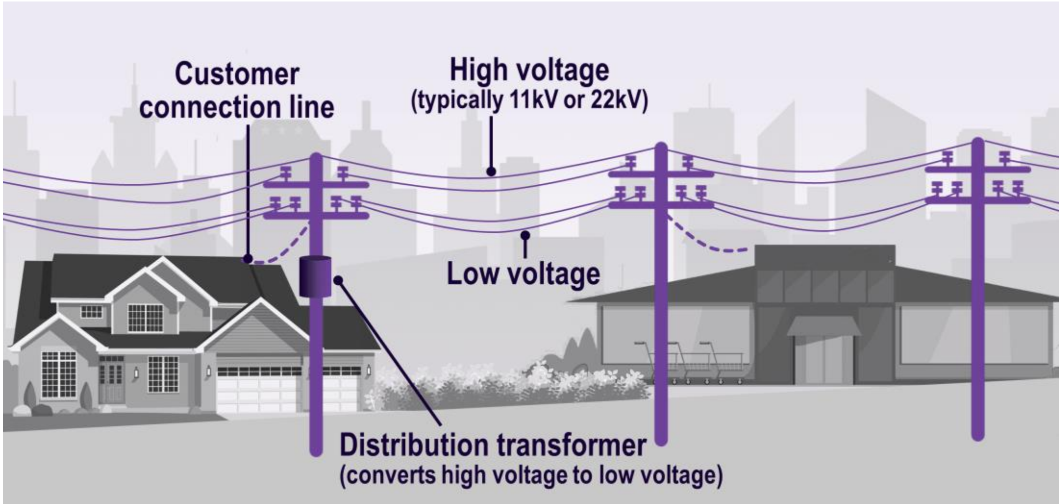
As discussed in section 1.2, our exemplar is a single hypothetical urban supply area with about 1,900 customers, characterised by:

— higher than typical exposure to wind and vegetation related outages

— higher than typical reliance on overhead distribution infrastructure.

This exemplar represents a single hypothetical feeder, which is a high voltage trunk supply line, and the associated infrastructure to deliver power to all connected customers, including transformers, low voltage power lines and connection points (see Figure 2.3 for a depiction of how overhead electricity distribution infrastructure typically looks in Victoria).

Figure 2.3 Typical overhead electricity distribution infrastructure in Victoria



The characteristics of this hypothetical exemplar feeder are based on the characteristics and performance of 54 real-world feeders termed the 'exemplar sample'.[1] This exemplar sample is drawn from feeders in more heavily vegetated suburbs of Melbourne but, as noted in section 1.2, reflects supply conditions in a range of urban areas across the state.

The 54 sample feeders were identified by analysing the performance data of a broad range of feeders over the period 1 January 2018 to 30 June 2022 and identifying those that:

— are defined as urban

— had a level of unplanned outages between the 75th and 95th percentiles of those feeders

— had a share of overhead feeder distance that was above the median of the feeders considered (i.e. it was at least as high as a 'typical' feeder).

The characteristics of the exemplar and the exemplar sample are summarised in Table 2.1.

[1] The use of a broad exemplar sample reflects the fact that, while the historical performance of any single feeder is known, the future performance of that feeder is unknown, and so modelling future outcomes based on the historical performance of a single feeder (or a small sample) would be unreliable compared to modelling based on typical characteristics of a large sample.

Table 2.1 Exemplar and exemplar sample key statistics

	Exemplar	Exemplar sample		
		Min.	Median	Max.
Overhead high voltage (HV) circuit distance (km)	7.7	1.9	7.7	20.3
Overhead share of HV lines	86%	76%	86%	97%
Overhead share of low voltage (LV) circuit distance and connections	89%	Data not available at feeder level		
Overhead LV circuit distance (km)	13.4	Data not available at feeder level		
Overhead HV circuit sharing poles with LV (km)	6.2	Data not available at feeder level		
No. of customers	1,938	70	1,938	4,966
Overhead customer connections	1,732	Data not available at feeder level		
Unplanned outages as a share of energy supplied	0.022%	0.013%	0.022%	0.035%
Feeder maximum demand (MVA)	5.5	1.2	5.5	10.1

Note: Where data are not available at the level of individual feeders we have inferred assumptions from network-wide data. HV circuits are typically operated at 11,000 volts or 22,000 volts in Victoria; we have assumed 22,000 volts. The overhead LV distance and connections share were estimated based on the difference (3 percentage points) between the overhead shares for feeders and for LV circuits across the feeders considered. Unplanned outages as a share of energy supplied was estimated by proxy using maximum demand data for each feeder, as energy supplied per feeder is not publicly reported.

Source: ACIL Allen analysis of economic benchmarking data provided by electricity distribution businesses to the Australian Energy Regulator.

We analysed the average load per customer by connection type (residential, non-residential non-demand tariff, low voltage demand tariff and high voltage demand tariff), the network load profile (ratio of peak demand to average demand) and the peak demand of the exemplar from Table 2.1 to estimate the sectoral composition of demand for the exemplar (Table 2.2).

Table 2.2 Sectoral composition of exemplar electricity demand

	Residential	Commercial	Industrial	Total
Total customers	1,760	172	6	1,938
Share of customers	90.8%	8.9%	0.3%	100%
Total electricity consumption (MWh)	8,125	8,084	2,411	18,620
Share of electricity consumption	43.6%	43.4%	12.9%	100%
Annual average electricity consumption per customer (MWh/year)	4.6	47.0	376.7	

Source: ACIL Allen analysis of network economic benchmarking data and Table 2.1.

2.2.3 Potential adaptation actions

Infrastructure Victoria's prior research identified 13 potential adaptation measures under four categories (see Box 2.1 for the definitions of these categories):

— **Higher-cost infrastructure**: underground assets, microgrids, pole replacement program, new lines on alternative routes, and fit spark plugs and surge arresters.

— **Lower-cost infrastructure:** increased or revised vegetation clearance and management, and reinforcing structures.

— **Maintenance:** self-healing networks.

— **Hazard management:** automated or remote asset inspection / monitoring devices, electrical isolation, stand-alone power systems (SAPS), energy back-up systems at community hubs / key sites and earth wires.

Box 2.1 Definition of adaptation types

Higher-cost infrastructure

Higher-cost infrastructure can include the use of physical structures to reduce the impacts of climate change. Investments are generally more capital intensive with examples including new construction, upgrades or significant reinforcement of infrastructure. This involves engineering solutions to the infrastructure under consideration or the surrounding system such as through protection measures.

Lower-cost infrastructure

Lower-cost adaptation measures can be simple and can also involve smaller investments that are modular, flexible and scalable. Lower-cost adaptation can include measures that interact with the natural environment, such as nature-based solutions. Nature-based solutions use characteristics of natural features and processes, or mimic it through human design and engineering, providing both risk reduction and ecological benefits.

Maintenance

Maintenance adaptation refers to altering maintenance regimes so that existing infrastructure remains resilient and functional in the face of changing climate conditions. Periodic and preventative maintenance regimes can be examined. Periodic maintenance adaptation refers to altering the set schedule for inspection and repair of assets to account for changing conditions. Preventative maintenance refers to the use of predictive analysis to proactively forecast asset failure and reduce the risk of failure by scheduling maintenance ahead of time based on historical data. Maintenance initiatives can also involve various technologies used for monitoring hazards and infrastructure condition.

Hazard management

Hazard management adaptation refers to improving operational plans for managing extreme weather events and natural disasters. Hazard management can be quite broad and cover areas such as preparation before an extreme event, response during an event and immediate recovery. This can include, and is not limited to, early warnings, user awareness and behaviour campaigns, communication of information during and after times of disruption or incidents, measures to ensure a level of service continuity, emergency repairs, removal of hazards, temporary set-up of structures, and immediate actions to reduce cascading impacts.

Source: Sovacool 2011, 'Hard and soft paths for climate change adaptation', Climate Policy (11), pp.1178-1179, https://www.adaptation-undp.org/sites/default/files/downloads/sovacool-cp-hardsoft.pdf; NZ Government National Resilience Programme Business Case, https://www.nzta.govt.nz/roads-and-rail/highways-information-portal/technical-disciplines/resilience/national-resilience-programme-business-case/; US Government 2019, Nature-based solutions for coastal highway resilience: an implementation guide, https://www.fhwa.dot.gov/environment/sustainability/resilience/ongoing_and_current_research/green_infrastructure/implementation_guide/; World Roads Association, The World Roads Association 2019, Adaptation methodologies and strategies to increase the resilience of roads to climate change – case study approach, https://www.piarc.org/en/order-library/31335-en-Adaptation%20Methodologies%20and%20Strategies%20to%20Increase%20the%20Resilience%20of%20Roads%20to%20Climate%20Change%20%E2%80%93%20Case%20Study%20Approach, p. 49, ROADAPT 2015, Roads for today, adapted for tomorrow – Guidelines, prepared for the Conference of European Directors of Roads Transnational Road Research Program, https://www.cedr.eu/download/other_public_files/research_programme/call_2012/climate_change/roadapt/ROADAPT_integrating_main_guidelines.pdf, p.22.

ACIL Allen identified a further three potential adaptation measures:

— Tree replacement (lower-cost infrastructure category): large trees that have the potential to impact on overhead distribution infrastructure are removed and replaced with mature trees of a lower-growing species that will remain below the height of this overhead infrastructure. We categorised this measure as lower-cost infrastructure as it involves working with natural hazards in a flexible way with low capital expenditure.

— Grid-forming inverters (hazard management): as electricity customers adopt combined solar and battery systems they are required to install 'grid-forming' inverters that are capable of operating as a stand-alone or 'islanded' system for that customer in the event of a grid outage, reducing the cost of these outages. We categorised this measure as hazard management because it works to ensure continuity of service once a hazard has caused the power supply to be disrupted.

— Insulated cable (lower-cost infrastructure): existing overhead conductors are replaced with overhead insulated cables at the start of the modelling period, with other components replaced like-for-like as they reach the end of their life. We categorised this measure as lower-cost infrastructure as the investments involved are modular and incur relatively low capital expenditure.

Table 2.3 summarises our initial assessment of the suitability of each of the adaptation measures identified to mitigate the effects of extreme wind on urban electricity distribution network areas comparable to our exemplar.

Table 2.3 Initial assessment of suitability of adaptation measures

Adaptation measure	Effectiveness in mitigating the effect of extreme wind on urban electricity networks
Higher-cost infrastructure	
Underground assets	High. Effective adaptation measure, albeit at high cost.
Microgrids	Low. Extreme wind is likely to cause significant damage to the low-voltage network, which cannot be addressed through a micro-grid. It is not likely to be feasible to locate sufficient distributed solar generation to operate micro-grids in an urban area, which would necessitate an undesirable reliance on diesel generation. However, a microgrid may be more effective in a regional area with more room for local renewable electricity generation and longer feeder lengths that are subject to weather damage or other reliability risks.
New lines on alternative routes	Low. Power lines can be re-routed away from heavy vegetation, but this is only relevant for higher voltage lines because low voltage lines need to be located close to the loads they are supplying.
Lower-cost infrastructure	
Increased or revised vegetation clearance and management	Moderate. While increased vegetation clearance would reduce the risk of vegetation falling on powerlines, community expectations are for minimal vegetation clearance to maximise environmental and aesthetic benefits.
Reinforcing pole structures	Low. Would mitigate against power outages caused by wind events if any part of the pole structure is weak. Will only avoid outages caused by the failure of poles but not those caused by tree branches falling across power line conductors.
Pole replacement program	Low. Pole replacement will avoid power outages caused by the failure of poles but not those caused by tree branches falling across power line conductors.
Tree replacement	High. Tree replacement would remove large trees with significant risk of falling across or dropping branches on power line conductors, with this risk being particularly severe during major storm events. It would also greatly reduce the risk of incidental contact between branches and conductors.
Fit spark plugs and surge arresters	Not applicable as an adaptation measure as this equipment is already installed at scale in Victoria.
Insulated cable	Moderate. Insulated cable will avoid a range of power outages caused by vegetation and animal contact with power line conductors, but will not avoid outages caused by tree branches pulling down conductors.
Maintenance	
Self-healing networks	Not applicable, as all Victorian distribution networks are already implementing self-healing networks, such as enhanced fault location, isolation and service restoration technologies, to varying degrees.

Adaptation measure	Effectiveness in mitigating the effect of extreme wind on urban electricity networks
Energy back-up systems at community hubs / key sites	Low. Would mitigate a small portion of the impact of long-duration power outages, irrespective of cause, assuming the energy back up system is maintained. Unlikely to be utilised in the case of routine, shorter-duration power outages.
Hazard management	
Automated or remote asset inspection / monitoring devices	Not applicable, as all Victorian distribution networks are regularly implementing improvement initiatives such as enhanced remote monitoring using digital twin technology. Power outages can already be remotely detected using smart meters.
Electrical isolation	Not applicable as an adaptation measure as this equipment is already installed at scale in Victoria.
Earth wires	Not applicable as an adaptation measure as this approach is only effective in preventing power outages from lightning, not wind.
Stand-alone power systems (SAPS)	Low. Well-treed areas that are most susceptible to wind are generally not suitable for SAPS due to limited flat, clear land for solar installation, which would require significant diesel use (resulting in high costs, high emissions and unacceptable local noise and pollution impacts). SAPs are also more cost-effective in rural areas where the average length of power lines per connection is much higher than in urban areas
Grid-forming inverters	Moderate. When coupled with solar-battery systems, these inverters allow individual customers to operate on a stand-alone or 'islanded' basis, and so can avoid power outages of all kinds, including those from extreme wind. However, unlike SAPS, some level of outage is acceptable and so diesel back-up is not required. In general sufficient solar and battery capacity is needed to provide a meaningful volume of supply when islanded, which is more feasible for residential and small commercial loads than larger commercial and industrial loads.

Note: The suggested allocation of adaptation measures reflects the category definitions provided in *Box 2.1*. The precise categorisation of measures is dependent on a range of assumptions about how it would be applied in a specific context.

Source: ACIL Allen analysis

This initial review of effectiveness identified five measures that were clearly more effective than the others in an urban context (some measures, such as micro-grids, SAPS and installing new lines on alternative routes, are more effective in rural contexts):

— undergrounding
— tree replacement
— grid-forming inverters
— insulated cable
— increased or revised vegetation management.

We then further considered the merits of these measures against criteria including community acceptance, financial cost and the risk of maladaptation, that is, avoiding outages from extreme wind but creating significant exposures to other kinds of outages. Based on this assessment, enhanced vegetation management was not selected for further analysis due to concerns about community acceptance, specifically the feasibility of further strengthening electric line clearance regulations given community and local government opposition. Tree replacement is a comparable measure and would also face some community and local government opposition, but it offers a higher degree of effectiveness and a strong economic case could increase community acceptance.

Reflecting these considerations, we defined five scenarios to analyse the effects of four adaptation actions against our base case:

— The **base case**: existing overhead distribution infrastructure is replaced like-for-like incrementally as individual components reach end-of-life.

- **Scenario 1 (undergrounding)**: existing overhead distribution infrastructure is replaced with equivalent underground infrastructure at the start of the modelling period.
- **Scenario 2 (tree replacement)**: large trees that have the potential to impact on overhead distribution infrastructure are removed and replaced with mature trees of a lower-growing species that will remain below the height of this overhead infrastructure.
- **Scenario 3 (grid-forming inverters)**: as electricity customers adopt combined solar and battery systems they are required to install 'grid-forming' inverters that are capable of operating as a stand-alone or 'islanded' system for that customer in the event of a grid outage, reducing the cost of these outages.
- **Scenario 4 (insulated cable)**: existing overhead conductors are replaced with overhead insulated cables at the start of the modelling period, with other components replaced like-for-like as they reach the end of their life.

The need to adapt infrastructure to climate change impacts is central to this analysis, and so is also integrated into the design of the scenarios (see section 2.1.2).

2.3 Estimating costs

2.3.1 Capital expenditure

ACIL Allen engaged expert cost estimation services from WT Partnership to advise on the capital costs involved in each of the modelled scenarios. GHD provided qualitative engineering advice to ensure the robustness and overall feasibility of the modelled scenarios.

Base case

We estimated the cost of replacing existing overhead infrastructure as a single project. In practice, existing network infrastructure will be of varying ages and conditions and will be replaced periodically over its working life (assumed to be 50 years for this project), so we spread this cost as equal instalments of 1/50th of the total cost over each year of the projection. We estimate the cost to be $10.0 million based on the following assumptions:

- exemplar defined as per Table 2.1
- 50 metre spacing between poles, which are assumed to be timber
- all works to zone substations, switchgear, customer switchboards and meters are excluded
- 13 megaVolt-amps of distribution transformation capacity (consistent with our analysis of the typical network-wide ratio of transformation capacity to feeder maximum demand), consisting of 300 kiloVolt-amp pole-mounted transformers
- 20 metre distance for customer connection lines
- a 20% increase in the cost of this work to reflect that it will occur as a series of small projects, rather than as a single larger project with economies of scale in planning and delivery.

Scenario 1: undergrounding

We estimated the cost of decommissioning existing overhead infrastructure and replacing it with equivalent underground infrastructure as $20.3 million based on the following assumptions:

- exemplar defined as per Table 2.1
- 100mm of stabilised sand around all conduits, with 700 mm of cover above conduits
- excavated material is classified as virgin material suitable for landfill disposal
- 100 metre spacing between service pits for both high and low voltage circuits
- all works to zone substations, switchgear, customer switchboards and meters are excluded

- 13 megaVolt-amps of distribution transformation capacity (consistent with observed ratios of transformation capacity to feeder maximum demand), consisting of 500 kiloVolt-amp ground-mounted transformers
- 20 metre distance for customer connection lines
- basic landscaping to rectify works.

We assumed that this cost would be spread over three equal instalments from 2025 to 2027, reflecting the need to plan and stage the undergrounding project.

Scenario 2: tree replacement

We estimated the cost of removing an initial mature tree of up to 12 metres height and replacing with a mature low-growing tree at $4,400 per tree. This costing includes an allowance of four hours of labour working at height to remove branches and ensure sufficient clearance around live wires prior to removal.

We used Google Maps to visually analyse the streetscape in five areas served by multiple feeders in the exemplar sample, covering a total of 35 kilometres of overhead circuit distance, and estimated that the exemplar sample has about 23 trees per kilometre that would need to be removed to avoid interaction with power lines. This estimate includes both trees that would grow into power lines without ongoing clearance, or those with a significant risk of dropping branches on, or falling across, power lines in the event of high winds. The exemplar has almost 15 kilometres of total overhead circuit distance (1.5 kilometres of standalone high voltage circuit, plus 6.2 kilometres of co-located high and low voltage circuits and 7.1 kilometres of standalone low voltage circuit), which implies almost 350 trees would need to be replaced under this scenario.

The total cost of replacing these trees for this scenario is almost $1.6 million, which we assumed would be incurred over the period 2025 to 2027.

As the network continues to operate in its existing form under this scenario, the capital costs incurred in the base case were also incurred in this scenario.

Scenario 3: grid-forming inverters for solar-battery systems

We estimated the incremental cost of installing a grid-forming inverter in place of a standard ‘grid-following’ inverter for three inverter capacities: 5 kW, 7.5 kW and 15 kW as $4,308, $5,290 and $12,799 respectively. We assumed that these cost premia would decrease by 4% per year in inflation-adjusted terms, reflecting technological improvements and more competition to supply this equipment.

We estimated the total stock of battery systems connected to the exemplar feeder by:

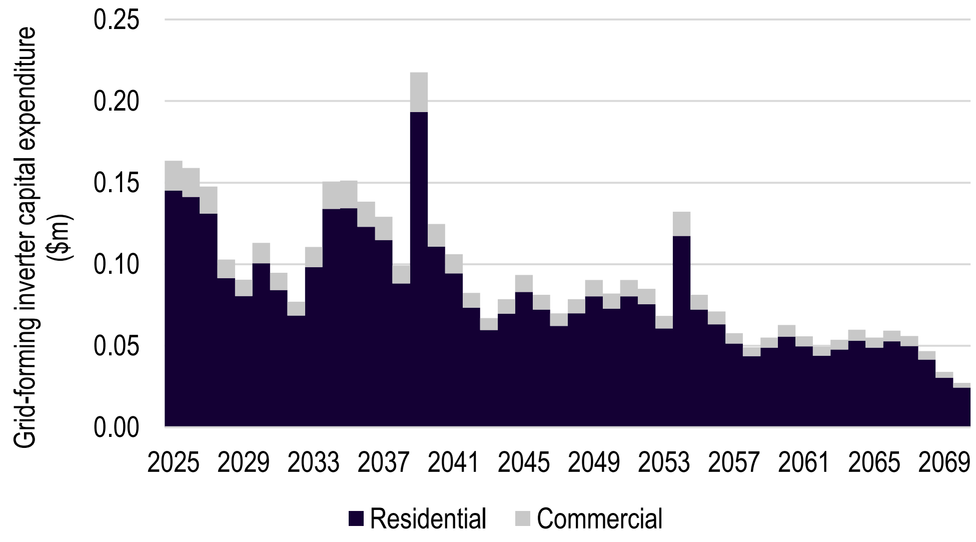
- assuming the Australian Energy Market Operator’s projected uptake of small-scale battery capacity for the 2022 Integrated System Plan’s Step Change scenario[xv]
- calculating the implied penetration of batteries based on the ABS’s projection of Victorian household numbers,[xvi] which indicates that the share of customers with batteries is likely to increase from around 6% in 2025 to 27% by 2050
- assuming the uptake of 5 kW inverters by households, 7.5 kW inverters by small businesses and 15 kW inverters by large commercial customers, based on the proportion of customers in each of these segments in Table 2.2
- assuming that inverters would require replacement after 15 years.

These assumptions resulted in a varying profile of incremental capital expenditure on grid-forming batteries, with initial increases driven by a growing stock and a relatively high cost premium over grid-following inverters, with these costs declining in the long-term as the stock of batteries matures and the cost premium declines (Figure 2.4).

The total undiscounted, inflation-adjusted incremental cost of grid-forming inverters is estimated to be $4.1 million based on these assumptions.

As the network continues to operate in its existing form under this scenario, the capital costs incurred in the base case were also incurred in this scenario.

Figure 2.4 Annual capital expenditure on grid-forming inverters, by customer segment



Source: ACIL Allen analysis

Scenario 4: insulated cable

We estimated the cost of replacing existing overhead uninsulated wires with equivalent insulated cables (at both high and low voltages) as $3.8 million, using the same general assumptions as in the base case, as well as costs for:

— removal and disposal of existing cable
— replacement with new insulated cable
— modifications to pole top hangers and insulators to accommodate the new cables
— modifications to consumer connections to connect to the new cables.

Cable insulation can be applied in several ways, but we have costed an arrangement known as ‘aerial bundled cable’, where the three conducting wires are individually insulated and wound together as a bundle which can use a common fixing point. It is also possible to insulate wires but not bundle them, with multiple fixing points on a cross-arm as used for typical bare wire circuits.

We assumed that this cost would be spread over three equal instalments from 2025 to 2027, reflecting the need to plan and stage conductor replacement.

The costs of progressively replacing poles, transformers and customer connections are incurred as in the base case, reflecting that this infrastructure has not been replaced during the switch to insulated cable and will still need to be periodically replaced as it reaches the end of its life.

Summary of capital cost assumptions

We estimated costs in 2023 dollars and escalated these costs in nominal terms over the period 2023 to 2025. We then adjusted this nominal cost escalation using the RBA’s inflation assumptions to estimate the extent of inflation-adjusted cost escalation in real 2023 dollars (Table 2.4). Together these assumptions imply real cost increases of about 3% by 2025. All costs beyond 2025 were assumed to hold constant in real terms, that is, to increase with the general rate of inflation.

Table 2.4 Cost escalation and inflation assumptions

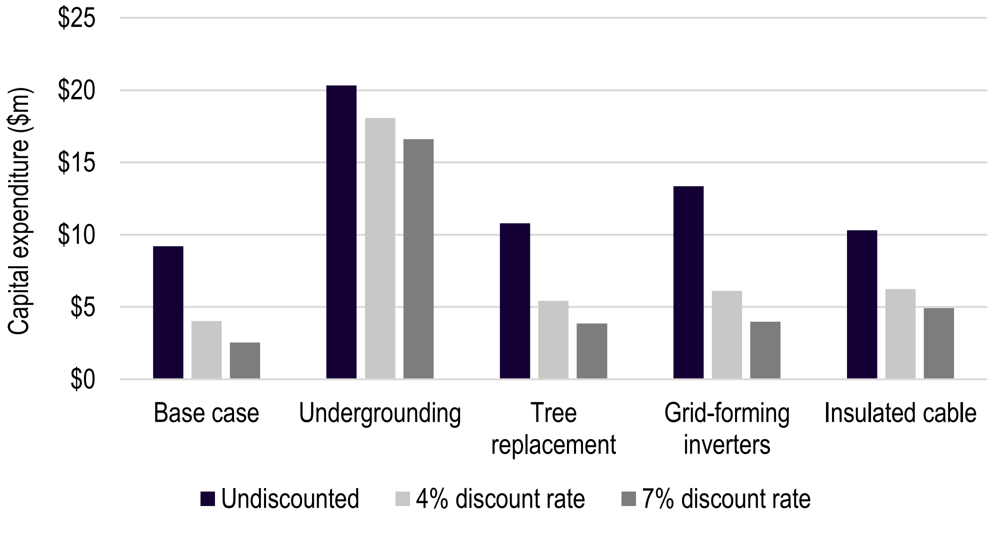
	2023	2024	2025
Nominal cost escalation	5.0%	4.4%	4.7%
Inflation	4.5%	3.25%	3%
Real cost index	1.005	1.016	1.033

Source: WT Partnership estimates; RBA 2023, Statement on monetary policy – May 2023, https://www.rba.gov.au/publications/smp/2023/may/economic-outlook.html#:~:text=Economic%20growth%20is%20expected%20to,softness%20in%20recent%20activity%20data.

Capital cost assumptions listed above assume that the network infrastructure installed operates to the end of its expected design life (typically 50 years for electricity distribution infrastructure). Where overhead distribution infrastructure remains in place and is subject to risk of early damage and replacement due to storms (in the base case and all scenarios except scenario 1), this is incorporated as an explicit repair cost and incorporated as maintenance expenditure (see section 2.3.2).

The base case has the lowest capital expenditure in undiscounted and discounted terms, undergrounding (scenario 1) has the highest capital cost, with the other adaptation measures in between these two scenarios (Figure 2.5). The proportional difference between the base case and the various adaptation scenarios is greater when discounting is applied, because adaptation measures typically involve upfront expenditures, whereas capital expenditure is incurred progressively in the base case – and upfront expenditure has a higher present value when discounting is applied.

Figure 2.5 Present value of capital expenditure, by scenario and discount rate



Note: base case network expenditure is incurred in the tree replacement and grid-forming inverters adaptation scenarios, alongside scenario-specific expenditure on the relevant adaptation measures. Base case network expenditure on poles, transformers and customer connections are incurred in the insulated cable scenario, alongside scenario-specific expenditure on new conductors.

Source: ACIL Allen analysis

2.3.2 Operating and maintenance expenditure

Annual operating and maintenance expenditure for distribution network assets was assumed to be 1% of the capital cost of equivalent new infrastructure, which is a common industry metric for operating and maintenance cost estimates. We assumed that these costs were inclusive of storm repair and vegetation management costs, which we then netted out and estimated directly. Storm repair and vegetation management costs must be estimated directly for each scenario as they are significantly affected by the adaptation measures – for example, undergrounding essentially eliminates storm repair and vegetation management costs. The remaining network operating expenditure was calculated as 0.6% of the capital cost of the relevant infrastructure. These costs were identical in the base case, scenario 2 (tree replacement) and scenario 3 (grid-forming inverters), and higher in scenarios 1 (undergrounding) and 4 (insulated cable), reflecting the higher capital cost of these solutions.

Storm repair costs

We made a specific allowance for repair costs following an extreme wind event to reflect the fact that undergrounding will essentially remove these costs, and tree replacement and insulated cable will reduce these costs due to reduced risk of major tree damage. We calibrated these costs based on the AusNet distribution network's estimate of about $10 million in emergency repair costs following the October 2021 storms,[xvii] which affected over 200,000 of its almost 800,000 customers, of whom almost 13,000 were without supply for three days. When this impact is scaled to the level of our exemplar we estimated that about 22 customers would experience a major disruption of three or more days, and scaling repair expenditure in line with this indicates about $17,000 in total costs per storm event. This expenditure was probability-weighted to reflect that major storms do not occur every year (see section 2.4.1 on page 23).

Vegetation management costs

Vegetation management costs were a further category of operating expenditure estimated for each scenario. In the base case, vegetation management costs of about $0.03 million per year were estimated based on the assumption of about 350 major trees requiring regular management, incurring a cost of $380 per tree, with trees undergoing maintenance about once every four years. The cost and frequency estimates were derived from network vegetation management cost data[xviii] and applied to tree management undertaken by both networks and local governments.

We assumed that all vegetation management expenditure was avoided in scenarios 1 and 2. In scenario 1 all assets are undergrounded, meaning that the need to manage vegetation around power lines is entirely avoided. In scenario 2 all trees of a height sufficient to require ongoing maintenance are replaced, again avoiding this ongoing cost.

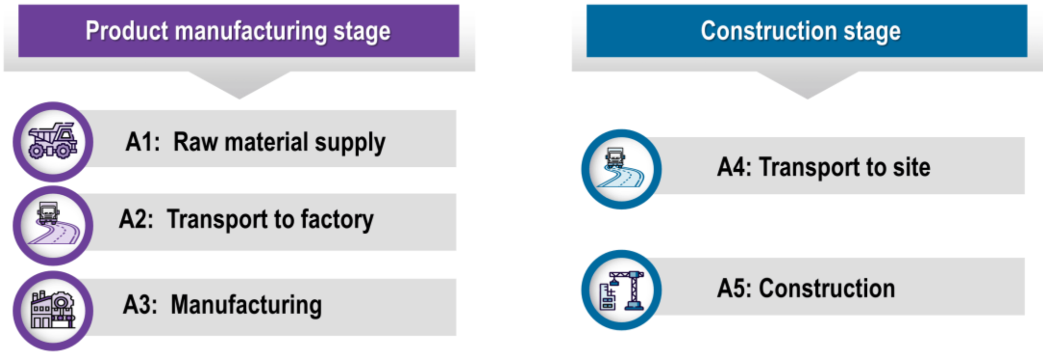
Scenario 3 (grid-forming inverters) incurs the same vegetation management costs as the base case, as there is no change to either the overhead infrastructure or the tree canopy.

Scenario 4 (insulated cable) involves a temporary reduction in vegetation management expenditure as insulated cable can be operated with lower clearance from vegetation than the bare wire used in the base case. We assume that vegetation management costs reduce to 20% of the base case cost in the first year after the full roll-out of insulated cable (2028) and return to 100% of the base case cost over the next five years as vegetation starts encroaching on the newly insulated wire.

2.3.3 Embodied emissions

WT Partnership estimated the embodied emissions of each adaptation measure for this study. We focused on 'upfront' emissions, which covers the embodied emissions of materials from extraction of raw materials, through manufacture, transport and installation (Figure 2.6). Emissions from the operation of assets post-construction are excluded, as are end-of-life demolition emissions.

Figure 2.6 Lifecycle carbon analysis modules considered in this analysis



Source: WT Partnership

For the base case and the undergrounding and insulated cable scenarios we estimated the embodied emissions of conductors, poles, transformers and customer connection lines, as well as the pits, trenching and conduits involved in undergrounding. For the tree replacement scenario, we estimated the emissions involved in removing and planting a tree, as well as the net reduction in carbon embodied in the tree that results when replacing a relatively larger tree with a smaller tree. We did not estimate the embodied emissions associated with grid-forming inverters, as the key difference between grid-forming and grid-following inverters will be in software, with negligible associated emissions. As with our estimates of capital costs, we assumed that the base case embodied emissions were also incurred in the tree replacement and grid-forming inverter scenarios, as the network infrastructure replacement required in the base case is also required in these scenarios.

Our analysis broadly followed current industry guidelines for the calculation of upfront embodied emissions, however, we note that these guidelines are still preliminary and are not yet agreed industry-wide. Due to the preliminary nature of the design documentation available for the investments, the embodied emissions estimates should be treated as indicative.

— For manufacturing embodied emissions (modules A1 to A3) we have used a variety of sources, including Environmental Product Declarations, the Epic, ICM and Etool database. A variety of databases are used to ensure as broad a coverage of building materials as possible.

— A full detailed estimation of embodied emissions in stages A4 and A5 (transport of materials to site and construction, respectively) would require significant contractor input and detail surrounding construction methodology, material transport distance and wastage allowances. In the absence of these details, we have allowed for a fixed materials transport distance of 200 kilometres to and from the site, and that construction emissions are 2.5% of material manufacture and transport emissions.

As with our estimates of capital costs, the time at which we assumed emissions were incurred varied depending on the nature of the measure:

— In the base case, emissions were assumed to be incurred progressively over the 50-year typical life of the infrastructure.

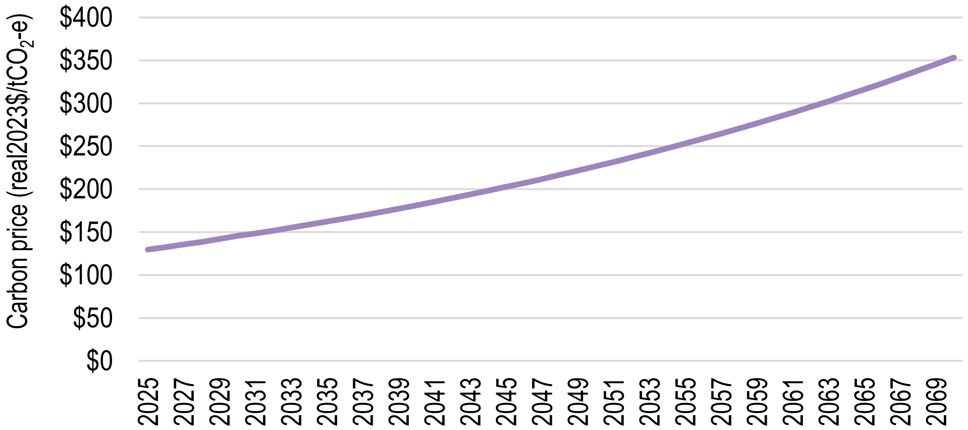
— In the undergrounding scenario, emissions were incurred over the years 2025 to 2027 in line with the construction schedule for this measure.

— In the tree replacement scenario, emissions were incurred over the years 2025 to 2027 in line with our assumed timeframe for replacing trees across the exemplar.

— In the insulated cable scenario, emissions for decommissioning bare wire conductors and replacing with insulated cable were incurred over the years 2025 to 2027, and emissions associated with periodic replacement of poles, transformers and customer connections were incurred progressively, as in the base case.

We used carbon price assumptions developed by the New South Wales Government for use in cost-benefit analysis, which are based on market carbon prices in the European Union Emissions Trading Scheme (Figure 2.7). While Australia does not have an emissions trading scheme comparable to that in place in Europe, the European carbon prices can be considered to be reflective of the society-wide costs of greenhouse gas emissions which should be reflected in a CBA.

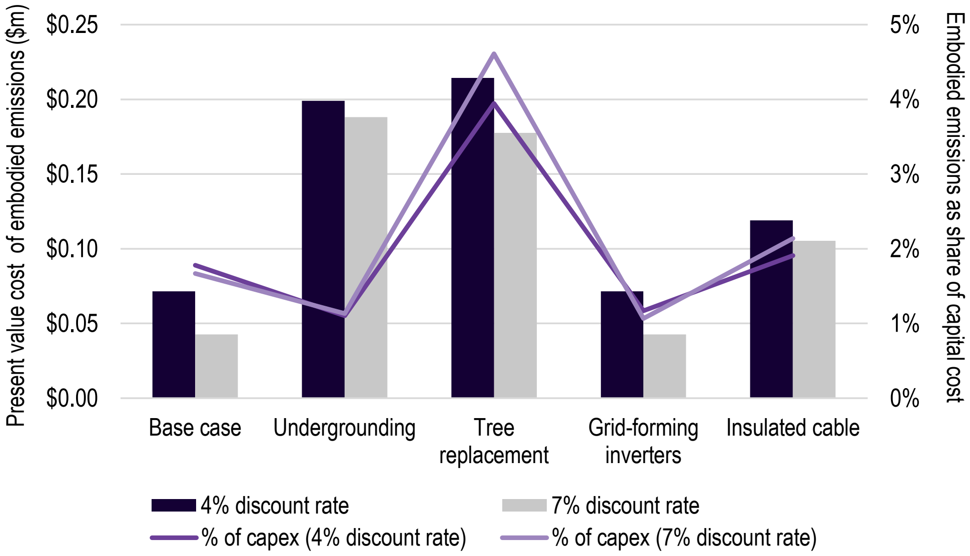
Figure 2.7 Carbon price assumptions



Source: NSW Government 2023, TPG23-08 NSW Government Guide to cost-benefit analysis, Technical note to TPG23-08: Carbon value in cost-benefit analysis, https://www.treasury.nsw.gov.au/sites/default/files/2023-03/20230302-technical-note-to-tpg23-08_carbon-value-to-use-for-cost-benefit-analysis.pdf.

Relative to the base case, the undergrounding, tree replacement and insulated cable scenarios incur a noticeable increase in embodied emissions, though the emissions cost using our assumed carbon prices is generally less than 2% of the total capital cost of each measure (Figure 2.8).

Figure 2.8 Present value of embodied emissions, total and as a share of capital cost, by scenario and discount rate



Source: ACIL Allen analysis

2.4 Estimating benefits

2.4.1 Electricity outages

A key source of benefits from the adaptation measures modelled is that they reduce power outages, particularly when the increasing effects of climate change on electricity distribution networks are considered. The discussion below details our assumptions on the level of power outages in the base case, and how these change across the adaptation scenarios.

Calibration to historical performance

We first calibrated the level of power outages in the base case to the historical performance of the exemplar sample described in section 2.2.1 across five outage cause categories:

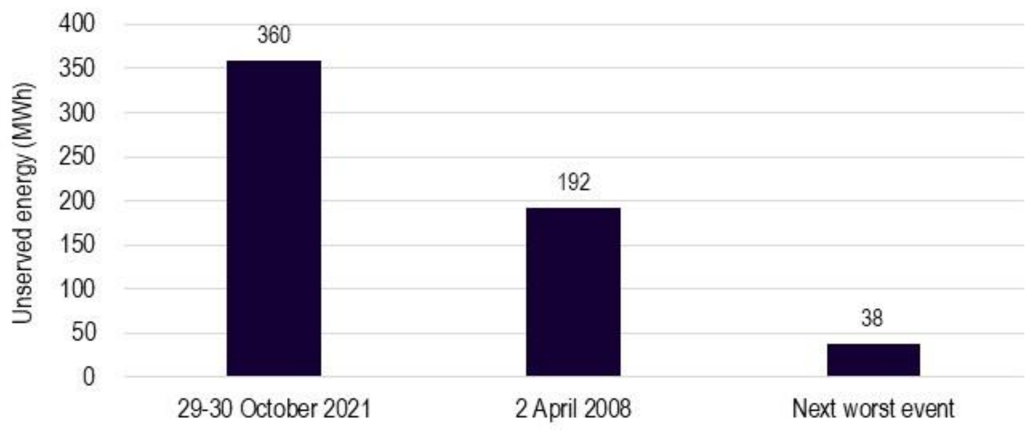
- weather and vegetation (which is of particular interest for this study as outages caused by extreme wind events are in this category)
- 'third party' outages, which are primarily outages caused by events such as vehicle impacts with power poles, or debris or construction equipment making contact with power lines
- animal, where animals such as possums or birds create contact between power line phases and short circuit the network
- asset failures
- planned outages for maintenance of the network.

This categorisation of outages is important as each of the network adaptation measures analysed will have different impacts on different outage types.

We analysed the level of power outages on each day over the period January 2008 to June 2022 inclusive in the exemplar sample to assess both the typical level of unserved energy and the probability and severity of major storm events that can impact the network.

This analysis showed that two major weather events, 2 April 2008 and 29-30 October 2021, caused significantly more unserved energy than was observed on any other day. Figure 2.9 shows that customers in the exemplar sample experienced 5-10 times the unserved energy on these two days compared to the next worst energy loss event. The median amount of unserved energy in the exemplar sample per day is only 0.015 megawatt-hours, or over 10,000 times less than what was experienced on 2 April 2008.

Figure 2.9 Unserved energy in the exemplar sample on major storm days



Source: ACIL Allen analysis

Accordingly, we further categorised outages as:

— **extreme**, which are major weather events that cause particularly widespread and longer-duration outages, reflecting the severity and duration of power outages observed on 2 April 2008 and 29-30 October 2021.

— **routine**, which reflects the typical level of power outages on all other days analysed, and consists of common and relatively localised outages, which are typically of relatively short duration.

As extreme outage events are weather driven, only vegetation and weather outages were categorised as extreme.

The results of this analysis are summarised in Table 2.5.

Table 2.5 Unserved energy by outage category in the base case, 2025

Outage category	Routine		Extreme	
	Annual unserved energy (MWh)	Share of unserved energy	Unserved energy per extreme weather event (MWh)	Share of unserved energy
Vegetation and weather	0.94	34%	5.13	100%
Third party	0.26	9%	0	0%
Animal	0.28	10%	0	0%
Asset failure	1.04	37%	0	0%
Planned	0.26	9%	0	0%

Note: vegetation and weather outages increase over time due to assumed increases in tree cover, in line with the *Living Melbourne* strategy

Source: ACIL Allen analysis of the exemplar sample

We have scaled the amount of unserved energy to reflect growing population density in the area served by the exemplar feeder. We analysed the rate of population and dwelling growth in eastern and south-eastern Melbourne to extrapolate likely trends in outages. The number of dwellings grew faster than population between the 2016 and 2021 censuses (1.5% per year and 0.8% per year), so we grew the volume of unserved energy by the average of these estimates (1.2% per year).

Effects of climate change

After calibrating the level of power outages in our model to the historical performance of our exemplar sample, we adjusted the expected level of outages to reflect the effects of climate change and, in particular, increasing extreme wind events. Climate change is likely to increase the effects of extreme wind on the overhead electricity distribution infrastructure in our exemplar and so the level of extreme outages in our base case has been increased to reflect this impact. This means that adaptation measures that reduce the effects of extreme wind on this infrastructure, and therefore reduce power outages, will have a larger effect and deliver a greater economic benefit than if climate change was not occurring.

To do this we analysed both historical and projected wind data to assess how the severity of extreme wind events may change in future due to climate change.

— Historical data was sourced from the Bureau of Meteorology, using data from three weather stations (Moorabbin Airport, Scoresby and Viewbank) to approximate the conditions of the exemplar region.[xix] Analysis found a strong link between extreme wind and extreme outage events, with both April 2008 and October 2021 incidents being the two highest recorded wind speeds over the analysed period.

— Projected wind data was drawn from the Victorian Climate Projections[xx] under Representative Concentration Pathways (RCPs) 4.5 and 8.5, examining locations across eastern and south-eastern Melbourne.

The analysis indicates that there is little change in forecast median wind speeds under both RCPs. By contrast, our analysis of downscaled projection data of our exemplar area (eastern and south-eastern Melbourne) does suggest some increase in the severity of extreme events, with forecast maximum wind speeds expected to grow slightly in the coming decades under the RCP 4.5 scenario.[2] However, these projections vary by location and are subject to some uncertainty – as noted in the Victorian Climate Projections technical report, extreme wind speeds could decrease in the future for some areas of Victoria.[xxi]

Despite the uncertainty noted above, our analysis assumes that both the severity and frequency of extreme wind events will increase in the future relative to observed historical outcomes. Based on the distribution of projected wind speeds, we assumed that the probability of observing an extreme event in a particular year is 19%[3], which is a significant increase on both the historical observation rate of extreme wind events, and the Victorian Climate Change Projections model predictions for historical years (the model produces projections from 2006). The impact of extreme winds is non-linear with wind speed and inherently difficult to predict, but the increased maximum winds speeds observed in the Victorian Climate Projections supports an assumption of increased weather and vegetation related outages. The literature did not directly support a specific value, and we assumed a 20% increase to allow for this factor.

Value of customer reliability

As is common in the electricity industry, we estimated the economic cost of power outages by multiplying the unserved energy (a volume of energy) by the value of customer reliability, or VCR (expressed as a dollar value per unit of unserved energy). We have used the Australian Energy Regulator's (AER's) published VCR estimates for this analysis. More information on how the AER estimates the VCR is provided in Box 2.2.

Our core estimates for this analysis reflect direct costs only. This is because of the relatively small-scale nature of our exemplar – reducing power outages for about 1,900 electricity customers is not likely to make a material impact to the level of traffic congestion or disruption to essential services that will arise across a wider area in the event of large and widespread outages. Further, these social costs are not relevant to routine outages, which only affect small numbers of customers at any one time. However, if adaptation measures were applied very broadly, they may start to avoid these wider social costs from extreme outages. To capture this effect we have applied a social cost multiplier to the cost of extreme outages as a sensitivity in section 3.3.

The AER's VCR estimates distinguish between:

— the season of outage (summer and winter)

— time of outage (peak and off-peak)

[2] Counter-intuitively, projections under RCP 8.5 do not forecast a rise in extreme wind occurrences, despite having higher global emissions concentrations. As a key focus of this study is on the effect of increasing wind severity on electricity distribution networks, we used RCP 4.5 as the base case in this modelling. Outcomes under the RCP 8.5 scenario are reflective of sensitivity analysis with lower severity of extreme wind events (see section 3.3).

[3] This is based on nine wind events in forty-seven projection years (from 2023 to 2070) that were of equal or greater intensity than wind events during the historical projection period (2006 to 2022). The projections did not indicate a clear pattern of increasing probability over time, so this increased probability was held constant throughout the model period.

— the type of user affected, distinguishing between residential, commercial and industrial customers, with commercial and industrial customers further disaggregated into small and large businesses.

Box 2.2 Estimating the value of customer reliability

Direct costs

The value of customer reliability reflects the cost to customers of a power outage, and therefore the benefit or value they would experience from more reliable supply. These costs include direct costs, such as food spoiling in a refrigerator, and opportunity costs, such as lost sales or production for businesses that must stop operating during a power outage.

The AER estimates the value of customer reliability through a mix of approaches:

— Residential and small business customers are surveyed to understand their willingness to pay to avoid hypothetical outages of different types (these techniques are called choice modelling and contingent valuation in the economic literature).

— Large business customers are directly surveyed to elicit information on the direct costs they experience during a power outage.

Social costs

As such, the AER's estimates only reflect the direct costs of power outages to electricity consumers, and do not pick up some broader issues that may arise during widespread and/or long-duration outages. Examples of these wider social costs include:

— traffic congestion and diversion of policing resources due to failure of traffic lights

— disruptions to essential services such as public transport, mobile and fixed-line telecommunications, and water and sewerage systems

— safety issues such as people being trapped in elevators, increased risk of crime due to failed streetlights, and inoperable fire alarms

— reliance on back-up power for essential services such as hospitals and prisons.

Source: AER 2019, Values of Customer Reliability Review – Final decision, https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/final-decision; AER 2022, Values of Customer Reliability – Update, https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/update-0, ACIL Allen 2020, Value of Customer Reliability for Widespread and Long Duration Outages, https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/aer-position.

We analysed the historical pattern of power outages to estimate the share of outages by season and time of day, and used the exemplar demand patterns in Table 2.2 to pro-rate the amount of unserved energy across different customer category types.

The AER's VCR estimates also vary by the duration of the outage and so we used data from our exemplar sample to estimate differences in the likely duration of outages for routine and extreme outages (Table 2.6), with extreme weather events causing relatively more long duration outages than routine events.[xxii]

Table 2.6 Distribution of outage duration, by outage type

	0-1 hours	1-3 hours	3-6 hours	6+ hours
Routine	41%	29%	19%	12%
Extreme	12%	16%	16%	56%

Source: ACIL Allen analysis of exemplar sample

We also adjusted the value of extreme outages to reflect their geographic reach. The standard VCRs assume a reasonably localised power outage. However, when an extreme wind event occurs and an outage is more widespread (for example, as occurred in Victoria on 2 April 2008 and 29-30 October 2021), people cannot easily mitigate the cost of the outage by travelling from the area without power to, for example, stay with family or friends who have power, or to purchase goods and services from shops that have power.

We increased the cost of extreme outages by 10% to reflect the cost of widespread outages as estimated in two studies. One study estimated how much electricity customers were willing to pay to avoid an outage that covered three provinces in Austria, compared to a localised outage in that customer's street,[xxiii] and the second study estimated customers' willingness to pay to avoid an outage that affected the whole country.[xxiv] Our adjustment is calibrated to a level reflective of outage events that affect customers over an area with a radius of between 5 and 85 kilometres. This is consistent with the geographic spread of the April 2008 and October 2021 events, which primarily affected metropolitan Melbourne.

Together, these factors support the overall VCR estimates for each customer category set out in Table 2.7. Routine outages have a higher cost per unit of unserved energy than extreme outages. This is because outages have a 'once-off' effect and cease to get worse over longer periods – for example, once food has spoiled due to a lack of refrigeration, no further food loss costs are incurred, even if an outage continues for a long time. This means that when the total costs of an outage are averaged over its entire duration, the average cost per unit of unserved energy is higher for shorter (routine) outages than for longer (extreme) outages.

Table 2.7 Value of customer reliability, by customer and outage type ($/kWh)

Heading	Routine	Extreme
Residential	$32.2	$22.8
Commercial	$81.6	$38.9
Industrial	$133.0	$62.1

Note: These estimates include direct costs to electricity users only. Routine outages are assumed to be localised, while the VCR for extreme outages is increased to reflect its more widespread geographic reach. Social costs are captured as a sensitivity in section *3.3*.
Source: ACIL Allen analysis

Effects of increasing tree canopy

The level of unserved energy resulting from vegetation and weather changes in the base case will increase not only because of climate but also because the level of tree cover in the exemplar area is likely to increase over time due to policy actions by local governments. In turn, this increased tree canopy will increase the level of both routine and extreme vegetation and weather outages, all else being equal.

This effect is captured through an outage 'severity factor' for weather and vegetation outages (it is not applied to other outage categories). The effect of increasing tree cover was captured by assuming that the level of tree canopy increases in line with targets set out in the *Living Melbourne* study, which has been endorsed by the vast majority of local governments in the Melbourne metropolitan area,[xxv] while some non-metropolitan councils have adopted similar objectives.[xxvi] This study indicates that the total level of tree canopy in the exemplar area is likely to increase from 20% in 2015 to 30% by 2050. We increased weather and vegetation outages in line with this relative increase in tree canopy.

Effect of adaptation measures

Each of the adaptation measures reduces the severity of an outage event in different ways. Table 2.8 summarises the reduction factors by outage cause and adaptation measure that we have assumed based on our knowledge and experience of the electricity distribution network and adaptation measures analysed.

Table 2.8 Share of outages avoided, by cause and by adaptation measure

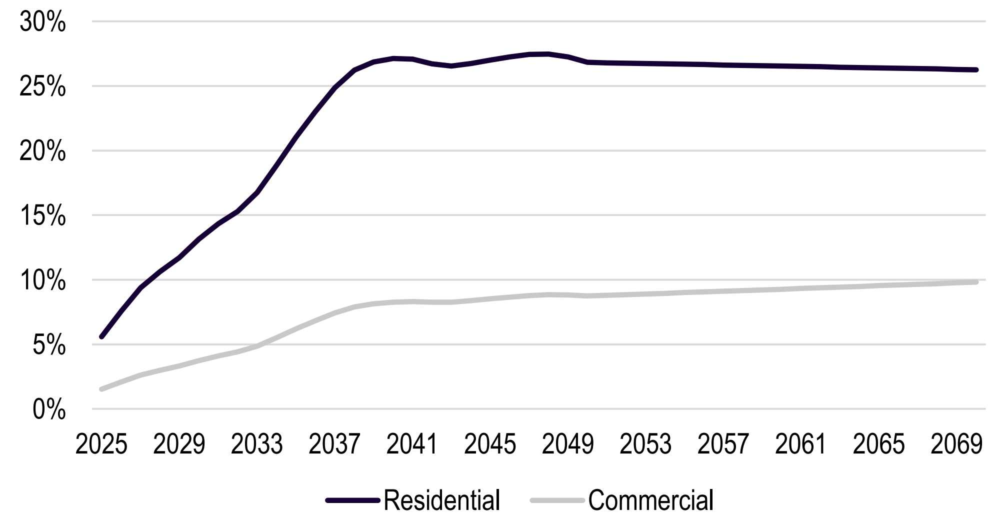
Outage cause	Routine / Extreme	Undergrounding	Tree replacement	Grid-forming inverters	Insulated cable
Vegetation/ weather	Routine	100%	67%	See Figure 2.10	50%
	Extreme	100%	80%	See Figure 2.10	25%
Third party	Both	100%	0%	See Figure 2.10	0%
Animal	Both	100%	80%	See Figure 2.10	100%
Asset failure	Both	80% initially, decreasing to 0% over 20 years	0%	See Figure 2.10	50% initially, decreasing to 0% over 20 years
Planned	Both	0%	0%	See Figure 2.10	0%

Notes: Tree replacement is assumed to be more effective in preventing extreme weather outages, as large and high-hanging branches are removed, which are a major cause of outages in storms. Conversely, insulated cable is assumed to be less effective on major storm days as cables remain close to large branches, which can be brought down in major storms. Undergrounding and insulated cable measures involve installing new infrastructure, which is assumed to reduce asset failure outages. As shown in the table, the reductions in outages are greatest initially but asset failures return to base case levels over time as these new assets age.

Source: ACIL Allen analysis

The share of power outages avoided by grid-forming inverters increases over time in line with the increasing stock of these inverters (Figure 2.10). Grid-forming inverters will be very effective in avoiding outages for those customers that install them, with our analysis indicating that typical battery and solar system capabilities will be sufficient to avoid over 90% of all outages, given that most outages are of relatively short duration. However, the share of customers with batteries is quite low, with Australian Energy Market Operator forecasts indicating that this share is likely to be around 6% by 2025 and increase to about 28% by 2050 (see section 2.3.1, page 16).

Figure 2.10 Share of outages avoided by grid-forming inverters, by customer type



Source: ACIL Allen analysis

Maladaptation

ACIL Allen, with support from technical advisors GHD, considered the potential for the adaptation measures analysed to cause 'maladaptation', that is, an increase in other power outage types as a side-effect of addressing outages from extreme wind.

Three maladaptation risks were identified, and all three were assessed to be immaterial to our analysis of overall outages, such that no specific allowance was necessary for these modes of failure:

— Underground cables could fail due to flooding. We assessed that underground cables generally have no issues with flooding, provided that the cable insulation is not also damaged.

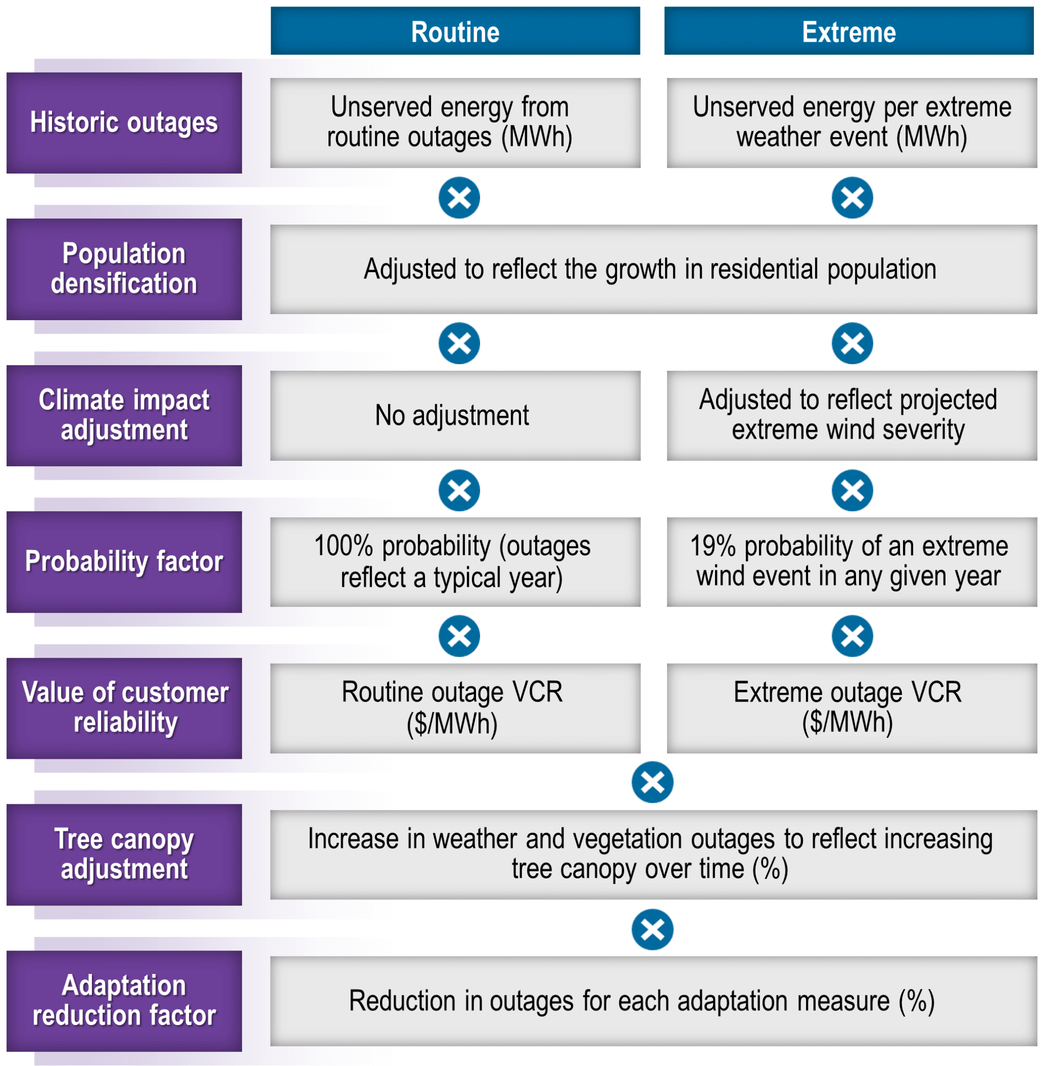
— Underground cables could fail due to dry soil cracking and moving. Current practice is to surround cables with stabilised sand when trenching, which isolates the cable from ground movements that may occur due to changes in soil conditions.

— 'Dig-ins' can occur, which is where digging equipment damages underground cables. We assessed the rate of dig-ins reported in distribution network performance reporting and found that this caused less than 0.1% of all outages for the CitiPower network, which has a relatively high proportion of underground cable.

Summary

An overview of our power outage cost quantification method is shown in Figure 2.11. The total annual cost of power outages is the sum of the annual routine outage cost and the probability-weighted extreme outage cost.

Figure 2.11 Power outage cost quantification method



Source: ACIL Allen analysis

2.4.2 Health effects of changes to tree canopy

As discussed in section 2.3.2, several of the adaptation measures analysed would change the extent of tree canopy that can be sustained in the vicinity of power lines. In turn, the extent of tree canopy has a significant impact on the temperature in a local area and can significantly reduce temperatures on hot days. It follows that increased tree canopy would reduce the impact of high temperatures and so improve the health of residents in the modelled exemplar area.

The health benefits of increased vegetation cover and the health costs of decreases in vegetation cover are calculated on the following basis:

— Just over 5,000 residents live in the area served by our exemplar feeder, calculated as 1,760 residential electricity customers multiplied by an average of 2.6 people per household.[xxvii]
— Eastern and south-eastern Melbourne experiences about 38 days over 30°C per year, based on Bureau of Meteorology data.
— A 10% increase in the share of land covered by tree canopy is assumed to reduce the land surface temperature by 1.13°C.[xxviii]
— The health benefit from cooling is assumed to be $2.90 for each degree reduction per person per day above 30°C.[xxix]

As noted in section 2.4.1 (on page 26), we estimated that the base level of tree canopy cover in 2015 was 20%, based on a weighted average of local government areas in eastern and south-eastern Melbourne, and assumed this would increase to 30% by 2050 in-line with local government-specific targets set out in the *Living Melbourne* strategy.[xxx] Further, we estimated that 23% of all tree canopy is affected by electricity infrastructure, calculated as 80% of the canopy located in infrastructure corridors (which are primarily roads) and a small share (20%) of residential and parkland tree canopy.[xxxi]

We further adjusted our estimates of health effects based on the Victorian Climate Projections RCP 4.5, which predict an increasing number of days over 30°C.[4]

Relative to the base case:

— Undergrounding (scenario 1) increases the extent of tree canopy, as the potential for conflict between power lines and trees is removed. We have assumed that undergrounding can support a 20% increase in the tree canopy affected by electricity distribution networks. This is equivalent to a 1.0% to 1.4% increase in the total tree canopy in the study area.[5]
— Tree replacement (scenario 2) significantly reduces the tree canopy, as large trees with significant shading effects are moved and replaced with lower-growing species that provide less shade. We have assumed that this results in a 50% reduction in the tree canopy affected by electricity distribution networks (a 2.6% to 3.4% reduction in the total tree canopy for the study area).
— There is no change in tree canopy associated with installing grid-forming inverters (scenario 3).
— Use of insulated cable (scenario 4) increases the extent of tree canopy, as insulated cables can be in closer proximity to vegetation with lower likelihood of causing power outages. We assumed that use of insulated cables supports a 10% increase in the tree canopy affected by

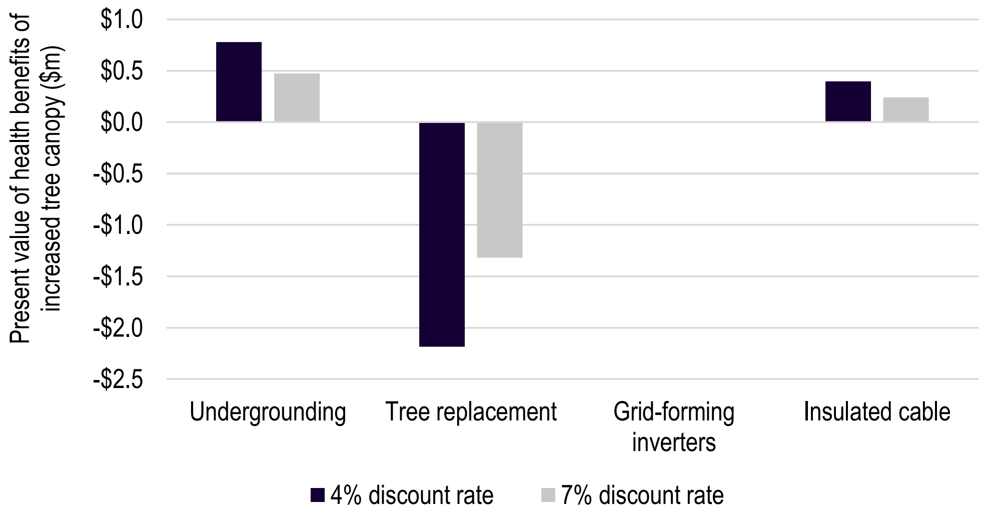
[4] We tested outcomes under RCP 8.5 and found that this effect was not material.

[5] This is calculated as the base level of tree canopy of 20% to 30%, of which 23% is affected by electricity distribution infrastructure, and which is then increased by 20%. Multiplying these factors together gives a total increase in tree canopy of 1.0% to 1.4%.

electricity distribution networks (a 0.5% to 0.7% increase in the total tree canopy for the study area).

Together, these assumptions indicate that undergrounding and insulated cable investments can deliver meaningful health benefits to residents of our modelled exemplar area due to increased tree canopy, while tree replacement is estimated to incur a significant health cost due to reduced tree canopy (Figure 2.12).

Figure 2.12 Present value of health benefits due to changes in tree canopy, relative to the base case, by scenario and discount rate



Source: ACIL Allen analysis

2.4.3 Reduced vehicle collisions with power poles

Overhead electricity infrastructure uses many street-side poles, creating a large number of potential traffic hazards. Consequently, undergrounding power lines would remove the risk of vehicle collisions with these poles, although the risk would remain that vehicles that currently collide with power poles would instead collide with trees or other fixed objects.

We estimated the cost of vehicle crashes involving power poles within our exemplar as a basis for then estimating the benefits of avoided crashes from undergrounding. To do this we first identified urban crashes involving power poles that resulted in fatalities or hospitalisations, and then translated this into a monetary cost of these crashes (Table 2.9).

Our exemplar represents about 0.11% of all the urban overhead power lines in Victoria by distance, so scaling down the total Victorian cost of crashes involving urban power poles ($194 million) indicates that the cost of traffic crashes involving power poles in our exemplar area is about $0.22 million per year.

The portion of these costs that will be avoided by undergrounding is difficult to quantify, as it requires assumptions about what would have happened had the vehicle not collided with a power pole. For simplicity we have assumed that undergrounding avoids 50% of these costs, or about $0.11 million per year. Other adaptation measures do not change the number or location of power poles, and so incur the same crash costs as the base case.

Table 2.9 Cost of urban traffic crashes in Victoria involving power poles

Casualty type	Urban crashes involving power poles		Cost per crash		Total cost
	2006-2020 (count)	Annual average	2013$	2023$	2023$m
Fatalities	173	11.5	$7,425,629	$9,615,609	$111
Hospitalisations	3,515	234.4	$87,988	$113,938	$27
Fatalities and hospitalisations					$138
Other accidents					$57
Victorian total					$194

Note: 71% of costs that arise from fatalities and hospitalisations was estimated based on Economic Connections (2017). Cost per crash was estimated using the willingness to pay approach in the Australian Transport Assessment and Planning guidelines.

Sources: Economic Connections 2017, Cost of Road Trauma in Australia, https://www.aaa.asn.au/wp-content/uploads/2018/03/AAA-ECON_Cost-of-road-trauma-summary-report_Sep-2017.pdf; ABS 2023, Consumer Price Index, Australia, https://www.abs.gov.au/statistics/economy/price-indexes-and-inflation/consumer-price-index-australia/latest-release; Australian Transport Assessment and Planning, Crash costs, https://www.atap.gov.au/parameter-values/road-transport/4-crash-costs, Table 14, VicRoads, Crash statistics, https://www.data.vic.gov.au/data/dataset/crash-stats-data-extract.

2.4.4 Broader changes in amenity

Changes to electricity network infrastructure and nearby tree canopy can have broader impacts on amenity than are captured in section 2.4.2:

— Undergrounding electricity infrastructure (scenario 1) is likely to increase amenity for local residents and visitors, as removing overhead electricity infrastructure can improve the aesthetics of the streetscape and reduce the number of physical obstacles for pedestrians. The amenity benefit of undergrounding may also be enhanced by allowing increased tree cover, which residents and visitors typically find visually pleasing, and which may contribute to health outcomes such as improved physical health due to better conditions for walking and improved mental health[xxxii] (these benefits are separate to the health benefits that result from increased tree canopy reducing local temperatures, which are discussed in section 2.4.2).

— Tree replacement (scenario 2) is likely to reduce the visual amenity created by large trees.

— The use of grid-forming inverters (scenario 3) is not likely to result in any changes to the streetscape or any relevant amenity changes.

— Use of insulated cable (scenario 4) can allow increased tree cover, which residents and visitors may find visually pleasing and therefore deliver amenity and health benefits.

Some relevant Australian literature examining amenity effects of electricity infrastructure and tree canopy changes is summarised in Box 2.3 on the next page.

Although the literature discussed above estimates the value of some of these amenity changes, we consider that these estimates cannot be rigorously extended to the specific circumstances of electricity distribution infrastructure in Victoria. The benefits estimated by various studies are likely to be context and location-specific, and are also sensitive to the estimation methodologies employed, meaning that using studies from other contexts to estimate amenity changes relating to the scenarios modelled in this study could be misleading. For example, house prices have increased significantly across Australia since the specific studies of the amenity benefits of undergrounding were undertaken, and it cannot be safely assumed these benefits have scaled linearly with house prices. Noting these concerns, we set out an indicative estimation of amenity benefits of undergrounding in chapter 4 to illustrate their likely materiality, and the value of further work to develop evidence applicable in contemporary Victoria.

Box 2.3 Literature analysing amenity effects of undergrounding electricity infrastructure and parkland

Undergrounding power in Western Australia

In 2011 the Economic Regulation Authority of Western Australia examined the costs and benefits of that state's ongoing policy to underground power with contributions from local governments and energy companies. It commissioned a 'hedonic valuation' study that compared house prices in areas with overhead and underground supply, while controlling for other factors that can affect house prices, and used this difference in house prices as a proxy for the amenity value that homeowners gain from having underground power supply. This study found a mean increase in house value from undergrounding of almost $10,000 (2011 dollars), or 2.6% of the mean house price at the time.

Undergrounding power in Canberra

McNair (2009) used hedonic valuation to compare house prices in three suburbs of Canberra with a mix of overhead and underground supply. This study found that underground power increases house prices by 2.9%, or about $11,700 per house (2009 dollars) based on the median house price in the study area.

McNair, Bennett and Hensher (2010) broadly confirmed this finding using a different estimation approach known as 'stated preference'. In this study, home-owners were surveyed on how much they valued underground power, and found they were willing to pay almost $7,000 per household (2010 dollars).

Amenity benefits of parks in Victoria

In 2018 Infrastructure Victoria and Aither (Evangelio et al.) examined the effect of parks on house prices in Victoria using the hedonic valuation method. This study found that moving from a median or typical distance from parks to the first percentile distance from parks is associated with an increase in house prices of $86,000. This indicates that homeowners place a significant value on the amenity benefits of parks.

Source: ACIL Allen analysis of: Economic Regulation Authority of WA 2011, Inquiry into State Underground Power Program cost benefit study, https://www.erawa.com.au/cproot/9988/2/20111020%20-%20D76272%20-%20Final%20report%20-%20inquiry%20into%20State%20Underground%20Power%20Program.pdf; McNair 2009, House prices and underground electricity distribution lines: the case of three selected suburbs in Canberra, https://openresearch-repository.anu.edu.au/bitstream/10440/1118/1/McNair_House2009.pdf; *McNair, Bennett and Hensher 2010, Households' willingness to pay for undergrounding electricity and telecommunications wires*, https://openresearch-repository.anu.edu.au/bitstream/10440/1115/1/McNair_Households2010.pdf; *Evangelio, Hone, Lee and Prentice 2018, What makes a locality attractive? Estimates of the amenity value of parks for Victoria*, https://www.infrastructurevictoria.com.au/wp-content/uploads/2019/04/What-makes-a-locality-attractive-Estimates-of-the-amenity-value-of-parks-for-Victoria.pdf.

2.4.5 Electrical safety benefits

Overhead electricity infrastructure can create a safety hazard, and so changes to this infrastructure can create welfare benefits by improving safety. Safety issues can arise due to contact between overhead infrastructure and construction or similar equipment, or when a major storm causes this infrastructure to fall over.

Energy Safe Victoria publishes annual reports on the safety performance of Victoria's electricity networks, and these include details of fatalities and major injuries that arise from contact with powerline infrastructure. ACIL Allen's analysis of these reports indicates that there have been 3 fatalities and 7 injuries from contact with urban overhead powerlines in Victoria over the last 5 years (financial years 2017-18 to 2021-22 inclusive).[xxxiii] As our exemplar represents about 0.11% of the urban overhead electrical infrastructure in Victoria by distance, this indicates that the probability of a major incident resulting in serious injury or death in our exemplar area is about 0.2% per year. As a result, we consider that the economic quantification of these safety benefits is not material to this cost-benefit analysis.

Major storms can cause electrical infrastructure to fall to the ground, potentially creating a safety hazard. That said, electrical infrastructure is designed so that contact of electrical conductors with the ground or other hazards will trigger protection equipment and normally isolate the circuit in question. In some cases, protection equipment may not operate as designed, but we are not aware of instances where this has resulted in electrocution. Emergency services typically assess infrastructure damage in major storms and work to protect the public from potential hazards. This may include the employment of security guards to patrol the fallen infrastructure. Reducing the risk of damage to overhead electricity infrastructure will reduce the probability that emergency services or security patrols will be required to protect the public from this hazard, but the economic quantification of these benefits is not material to this analysis.

2.4.6 Animal welfare benefits

Overhead electricity infrastructure is a common cause of electrocution of birds, possums, bats and other animals that make contact with live wires and short circuit the network (this also commonly causes power outages). Some of the adaptation measures analysed in this study can significantly reduce the risk of animal electrocution, and therefore improve animal welfare:

— Undergrounding reduces the risk of animal contact with power lines to almost zero.

— Tree replacement reduces the risk of animals climbing or falling onto overhead power lines, as the trees that are taller than typical distribution infrastructure have been removed and replaced with lower-growing species.

— Grid-forming inverters have no effect on animal welfare.

— Insulated cable virtually eliminates the risk of animal electrocution due to the protective effect of the cable insulation.

We are not aware of credible estimates of either the number of animals who are harmed by power lines in the Melbourne metropolitan area or other parts of Australia, nor the monetary value that humans would put on the welfare of these animals.[xxxiv] International studies have a high degree of uncertainty in their estimates[xxxv] and, in any case, the findings are unlikely to translate to Australia. Therefore, we have not attempted to quantify these benefits in this study but note that animal welfare benefits could improve the investment case of several of the modelled adaptation measures beyond the estimates in this study.

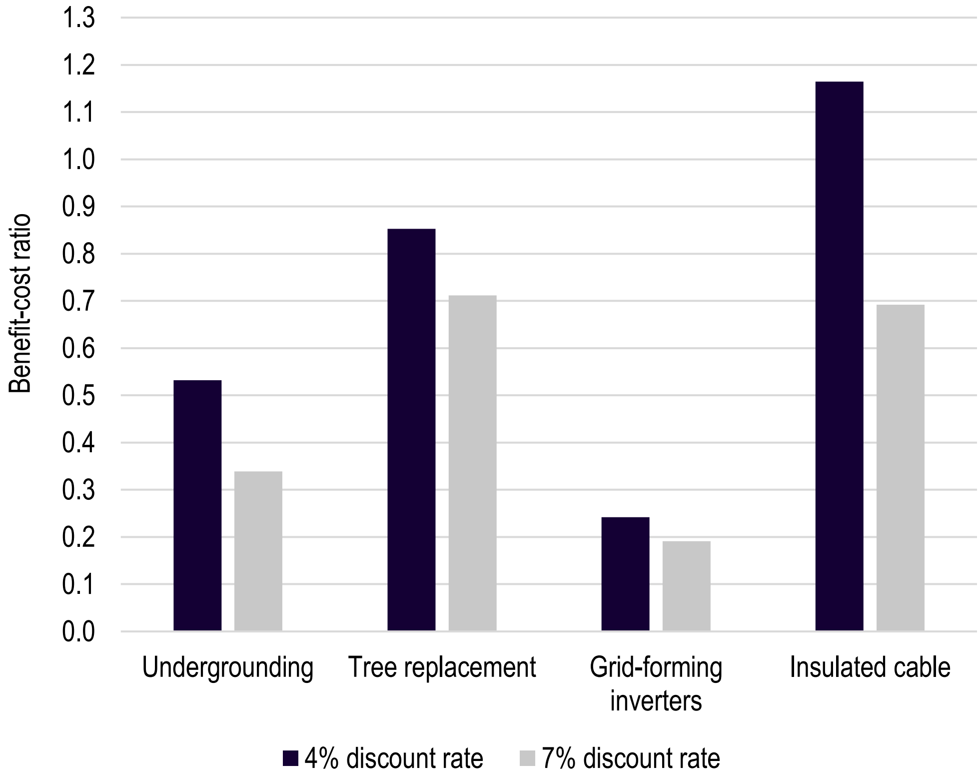
Results 3

3.1 Cost-benefit outcomes

As discussed in section 2.1, a cost-benefit analysis compares the costs and benefits of each adaptation scenario to the base case to determine the effects of each adaptation action.

Despite the modelled adaptation measures being effective in reducing electricity outages, our analysis finds that only one measure – insulated cable – achieves a BCR greater than one using a 4% discount rate, and no measure does so at a 7% discount rate (see Figure 3.1 and Table 3.1).[6] However, the tree replacement measure has a BCR approaching one (0.85) using a 4% discount rate.

Figure 3.1 Benefit-cost ratios, by scenario and discount rate



Source: ACIL Allen analysis

[6] As noted in section 2.1.4, a BCR of less than one indicates that the quantified benefits do not justify the projects, based on modelled assumptions and discount rates.

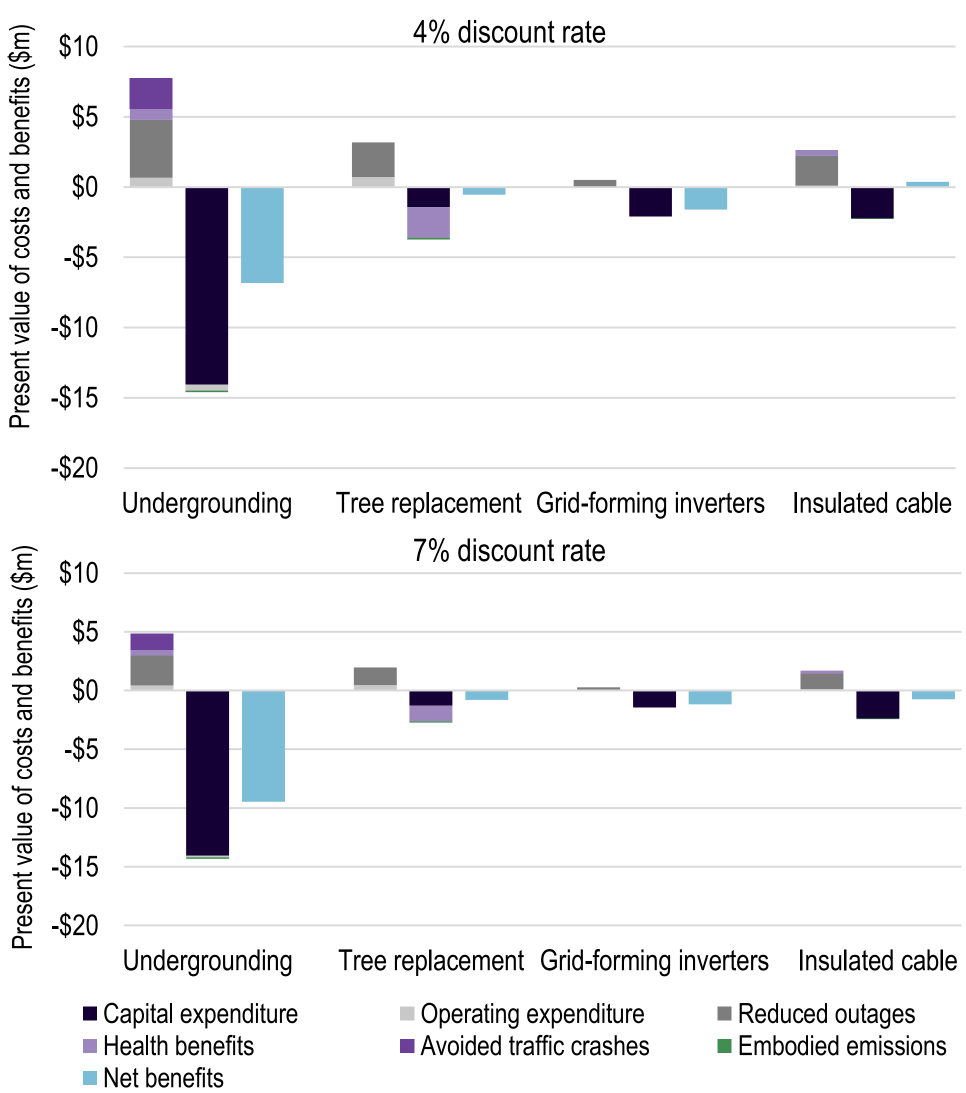
Table 3.1 Benefit-cost ratios, net present value and return on investment by adaptation scenario and discount rate

	4% discount rate		7% discount rate		
	BCR	NPV ($ million)	BCR	NPV ($ million)	Return on investment
Undergrounding	0.53	-$6.8	0.34	-$9.5	1.2%
Tree replacement	0.85	-$0.5	0.71	-$0.8	1.5%
Grid-forming inverters	0.24	-$1.6	0.19	-$1.2	-
Insulated cable	1.16	$0.4	0.69	-$0.8	4.7%

Note: no return on investment is presented if the value is negative (as a negative discount rate is not realistic) or not calculable (which occurs when a measure does not return a net benefit in any year of the modelling period).
Source: ACIL Allen analysis

Analysis of costs and benefits by category sheds some light on the drivers of the low BCRs for the analysed adaptation measures (Figure 3.2).

Figure 3.2 Present value of costs and benefits, by category, scenario and discount rate



Source: ACIL Allen analysis

In the case of undergrounding and grid-forming inverters, the capital expenditure on each of the adaptation measures is simply too high at this time to justify the benefits of reduced power outages due to extreme wind for our urban exemplar. The health benefits arising from increased tree cover and reduced traffic crash impacts due to undergrounding are not sufficient to change this outcome. However, as discussed in section 4.2, the unquantified amenity benefits of undergrounding could push the BCR of this measure above one.

In the case of tree replacement, the health costs of reduced tree canopy are a significant dis-benefit and drive the BCR of our exemplar below one – in the absence of this dis-benefit the measure would have a BCR of 2.1 using a 4% discount rate or 1.4 at a 7% discount rate. However, our estimated BCRs also exclude any amenity dis-benefits from replacing large trees with smaller trees (see section 2.4.4), and so are likely to over-estimate the net benefits of this measure.

3.2 Distributional outcomes

We analysed distributional outcomes across eight societal groups:

— the general base of electricity customers, which pays for costs incurred by electricity distribution businesses, separated into residential, commercial and industrial sub-categories

— local ratepayers, who incur costs for vegetation management through their local governments

— local residents, who directly benefit from reduced power outages and experience health benefits or costs due to changes in tree cover

— local commercial and industrial electricity consumers, who directly benefit from reduced power outages

— the wider community, which is affected by changes in greenhouse gas emissions and the impacts of traffic crashes.

Distributional outcomes by scenario at the 4% discount rate (Table 3.2) indicate that:

— for undergrounding and insulated cable measures, the general base of electricity consumers incurs significant costs in network investments, but the benefits are overwhelmingly realised by local residents and local electricity consumers

— for tree replacement, local ratepayers incur significant costs to implement the program and local residents experience significant health costs, while local commercial and industrial electricity customers enjoy fewer power outages and the broad base of electricity consumers incurs lower vegetation management costs

— for grid-forming inverters, the benefits and costs are incurred by the same parties, with the entities paying for the inverters also experiencing reduced power outages – but the benefits of these outages are not sufficient to pay for the inverters, so no group experiences a net benefit.

Table 3.2 Present value of net benefits by societal group ($ million), 4% discount rate

Societal group	Under-grounding	Tree replacement	Grid-forming inverters	Insulated cable
Residential electricity customers	-$7.8	$0.3	$0.0	-$1.2
Commercial electricity customers	-$4.8	$0.2	$0.0	-$0.7
Industrial electricity customers	-$1.4	$0.1	$0.0	-$0.2
Local ratepayers	$0.2	-$1.2	$0.0	$0.0
Local residents	$1.9	-$1.5	-$1.5	$1.0
Local commercial electricity customers	$2.0	$1.2	-$0.1	$1.0

Societal group	Under-grounding	Tree replacement	Grid-forming inverters	Insulated cable
Local industrial electricity customers	$1.0	$0.6	$0.0	$0.5
Wider community	$2.1	-$0.1	$0.0	-$0.0
Total net present value (NPV)	**-$6.8**	**-$0.5**	**-$1.6**	**$0.4**

Source: ACIL Allen analysis

Distributional outcomes are similar when using a 7% discount rate as when using a 4% discount rate (Table 3.3):

— All societal groups that experience a net benefit for a given measure using a 4% discount rate experience a net benefit using a 7% discount rate, and the same is true for groups that experience a net cost.

— The net benefits and net costs for societal groups are a similar order of magnitude at the 7% discount rate as the 4% discount rate.

Table 3.3 Present value of net benefits by societal group ($ million), 7% discount rate

Societal group	Under-grounding	Tree replacement	Grid-forming inverters	Insulated cable
Residential electricity customers	-$7.8	$0.2	$0.0	-$1.3
Commercial electricity customers	-$4.7	$0.1	$0.0	-$0.8
Industrial electricity customers	-$1.4	$0.0	$0.0	-$0.2
Local ratepayers	$0.1	-$1.2	$0.0	$0.0
Local residents	$1.1	-$0.9	-$1.1	$0.6
Local commercial electricity customers	$1.3	$0.7	-$0.1	$0.7
Local industrial electricity customers	$0.6	$0.4	$0.0	$0.3
Wider community	$1.3	-$0.1	$0.0	-$0.1
Total net present value (NPV)	**-$9.5**	**-$0.8**	**-$1.2**	**-$0.8**

Source: ACIL Allen analysis

3.3 Sensitivity testing

CBA outcomes are often very sensitive to the assumptions chosen, and these assumptions always carry a degree of uncertainty. Therefore it is common and prudent to use sensitivity testing to understand how variations in key assumptions affect the conclusions. The most important assumptions to sensitivity test are those that are material to the analysis and subject to a relatively high degree of uncertainty.

Reflecting this, we have chosen the following assumptions for sensitivity testing:

— Capital costs: increasing and decreasing capital costs by 30% for all investments (this degree of cost uncertainty is a reasonable expectation for the accuracy of the 'Class 5' capital cost estimates[7] that have been used in this study).[xxxvi]

[7] A Class 5 capital cost estimate is an early stage or concept screening estimate. See for example: GHD 2021, *ISP transmission cost database*, https://aemo.com.au/-/media/files/major-publications/isp/2021/transmission-cost-database---ghd-report.pdf?la=en, p. 28; and Christensen and Dysert 2005, *Cost estimate classification system – as applied in engineering, procurement and construction for the process industries*, p. 2.

— Extreme outage severity: increasing and decreasing both the frequency and the severity of power outages from extreme wind events by 20% for all scenarios, which results in a total increase in the cost of extreme outages of 44% or a total decrease of 36%.[8]

— Health costs: applying a 20% increase and a 20% decrease to the change in health costs caused by changes in tree canopy under the chosen adaptation measures.

In addition we have tested a sensitivity where we apply an additional social cost multiplier of 1.3 (that is, a 30% increase) to the high outage costs sensitivity. This sensitivity reflects that, if adaptation measures are applied widely, they may reduce a range of wider societal costs that are not likely to be fully captured within direct estimates of how households and businesses value reliability. Examples of these wider social costs include traffic congestion due to the failure of traffic lights, disruptions to essential services such as public transport, telecommunications and water and sewerage services, safety issues due to failures of equipment such as elevators, streetlights and fire alarms, and reliance on back-up power in facilities such as hospitals and prisons (see Box 2.2). We present the sensitivity analysis results for each scenario in the four tables below to assess whether outcomes for each adaptation measure are particularly sensitive to these assumptions.

Table 3.4 demonstrates that the CBA results for undergrounding are not highly sensitive to any of these assumptions. BCRs remain below 0.8 for all sensitivity-tested assumptions at the 4% discount rate, and equal to or below 0.5 at the 7% discount rate. This indicates that even quite significant changes in assumptions do not change the finding that, for urban supply areas similar to those modelled through our exemplar, undergrounding is not a cost-effective way to reduce electricity distribution network power outages from extreme wind.

Table 3.4 Sensitivity analysis of scenario 1: undergrounding

Parameter	Sensitivity	4% discount rate		7% discount rate	
		BCR	NPV ($m)	BCR	NPV ($m)
Core modelling results		0.53	-$6.8	0.34	-$9.5
Capital costs	+30%	0.41	-$11.1	0.26	-$13.7
	-30%	0.75	-$2.6	0.48	-$5.3
Extreme outage costs	+44% + social multiplier	0.78	-$3.2	0.50	-$7.2
	+44%	0.66	-$5.0	0.42	-$8.3
	-36%	0.43	-$8.3	0.27	-$10.4
Health costs	+20%	0.54	-$6.7	0.35	-$9.4
	-20%	0.52	-$7.0	0.33	-$9.6

Source: ACIL Allen analysis

Table 3.5 summarises the sensitivity analysis for tree replacement. Some sensitivities can push the BCR for this measure above one:

— High outage costs, with or without a social multiplier, push the BCR above one using a 4% discount rate.

— High outage costs plus a social multiplier push the BCR above one using a 7% discount rate.

This indicates that BCRs for tree replacement generally remain below one, even though there are some combinations of assumptions and discount rates where the measure could provide a positive economic return. This indicates that, even with favourable assumptions, tree replacement is

[8] If the frequency and severity of extreme wind events are both 20% higher the increase in outages will not be 40% but 44% because1.2 multiplied by 1.2 is 1.44, which is 44% higher than 1. Equally, if both factors are 20% lower the total reduction will be 36% not 40% because 0.8 multiplied by 0.8 is 0.64, which is 36% lower than 1.

unlikely to prove a consistently cost-effective way to reduce distribution network power outages from extreme wind.

Table 3.5 Sensitivity analysis of scenario 2: tree replacement

Parameter	Sensitivity	4% discount rate		7% discount rate	
		BCR	NPV ($m)	BCR	NPV ($m)
Core modelling results		0.85	-$0.5	0.71	-$0.8
Capital costs	+30%	0.77	-$1.0	0.62	-$1.2
	-30%	0.96	-$0.1	0.83	-$0.4
Extreme outage costs	+44% + social multiplier	1.43	$1.6	1.19	$0.5
	+44%	1.14	$0.5	0.95	-$0.1
	-36%	0.61	-$1.4	0.52	-$1.3
Health costs	+20%	0.76	-$1.0	0.65	-$1.1
	-20%	0.97	-$0.1	0.79	-$0.5

Source: ACIL Allen analysis

Table 3.6 demonstrates that the BCR and NPV of installing grid-forming inverters is very insensitive to a range of assumptions. BCRs remain below 0.5 for all sensitivities using a 4% discount rate, and below 0.4 using a 7% discount rate. This adaptation measure does not generate health benefits or costs, and so the results do not vary when we sensitivity test health benefit assumptions.

Overall, this indicates that even quite significant changes in critical assumptions are unlikely to change the finding that, at the present time, grid-forming inverters are not a cost-effective way to reduce power outages from extreme wind for urban parts of the distribution network similar to that modelled.

Table 3.6 Sensitivity analysis of scenario 3: grid-forming inverters

Parameter	Sensitivity	4% discount rate		7% discount rate	
		BCR	NPV ($m)	BCR	NPV ($m)
Core modelling results		0.24	-$1.6	0.19	-$1.2
Capital costs	+30%	0.19	-$2.2	0.15	-$1.6
	-30%	0.35	-$1.0	0.27	-$0.7
Extreme outage costs	+44% + social multiplier	0.45	-$1.2	0.36	-$0.9
	+44%	0.35	-$1.4	0.27	-$1.0
	-36%	0.15	-$1.8	0.12	-$1.3
Health costs	+20%	0.24	-$1.6	0.19	-$1.2
	-20%	0.24	-$1.6	0.19	-$1.2

Source: ACIL Allen analysis

Table 3.7 summarises the sensitivity analysis for insulated cable. This analysis shows that high capital costs or low base case outage costs can push the BCR of this investment below one using a 4% discount rate, whereas it is above one for the core modelling assumptions. This indicates that the investment case is sensitive to specific assumptions, and some caution must be used when interpreting the core modelling finding that this investment delivers a positive return for our modelled urban exemplar. Conversely, the measure can deliver a BCR of almost 2 if outage costs are high and the measure is applied widely to the point where it would materially reduce some of the wider social costs of outages (as represented by our social multiplier), indicating that under more favourable assumptions the measure would deliver a significant positive return. Only one of the sensitivities has a BCR above one using a 7% discount rate, which is where both outage costs are high and the social multiplier is applied.

Table 3.7 Sensitivity analysis of scenario 4: insulated cable

Parameter	Sensitivity	4% discount rate		7% discount rate	
		BCR	NPV ($m)	BCR	NPV ($m)
Core modelling results		1.16	$0.4	0.69	-$0.8
Capital costs	+30%	0.90	-$0.3	0.54	-$1.5
	-30%	1.65	$1.0	0.98	-$0.0
Extreme outage costs	+44% + social multiplier	1.98	$2.2	1.17	$0.4
	+44%	1.58	$1.3	0.93	-$0.2
	-36%	0.83	-$0.4	0.50	-$1.2
Health costs	+20%	1.20	$0.5	0.71	-$0.7
	-20%	1.13	-$0.3	0.67	-$0.8

Source: ACIL Allen analysis

Discussion and conclusions 4

4.1 Further investigating the benefits of insulated cable

As discussed in chapter 3 and highlighted by sensitivity analysis, the finding that insulated cable has a BCR of greater than one using a 4% discount rate should be interpreted with some caution. However, the high BCR of this measure relative to other measures suggests a strong case for further investigation of this approach to adapt electricity distribution networks to climate change.

An important area of uncertainty is the effectiveness of insulated cable in reducing outages, and this uncertainty may be able to be reduced at relatively low cost. Some networks routinely use insulated cable for replacement of low voltage circuits, and this could provide conditions for a 'natural experiment' to better understand its reliability benefits. Comparing the reliability of network sections that have insulated cable with the rest of the network could give greater confidence on the effectiveness of insulated cable in preventing power outages. Although this examination would not include the effect of insulated cable on outages occurring in the high voltage network, it would still be valuable for informing future decisions on the use of this adaptation measure.

4.2 Amenity benefits may justify undergrounding

The low BCRs estimated in this study (see section 3.1) indicate that undergrounding power lines in areas similar to our modelled urban exemplar is unlikely to be a cost-effective way to reduce power outages from extreme wind events. This finding holds despite the inclusion of other benefit categories, such as avoided vegetation management costs, improved health outcomes due to increased tree canopy, and avoided impacts from traffic crashes.

However, considering the amenity benefits that can arise from undergrounding (see section 2.4.3) could greatly strengthen the case for undergrounding electricity distribution infrastructure, and justify investment to capture both the amenity and network resilience benefits of this approach.

We have translated the findings of Australian studies on the amenity benefits of undergrounding to the context of current day Victoria. These estimates should be treated with caution given that studies used reflect conditions in Western Australia and Canberra from over a decade ago, and amenity benefits are likely to be very context-specific.

We used three methods to estimate indicative amenity benefits from undergrounding for our exemplar:

— Method 1: indexing the 2009, 2010 and 2011 estimates to present day dollars using the Consumer Price Index and then averaging, giving an estimated amenity benefit of about $13,000 per household.

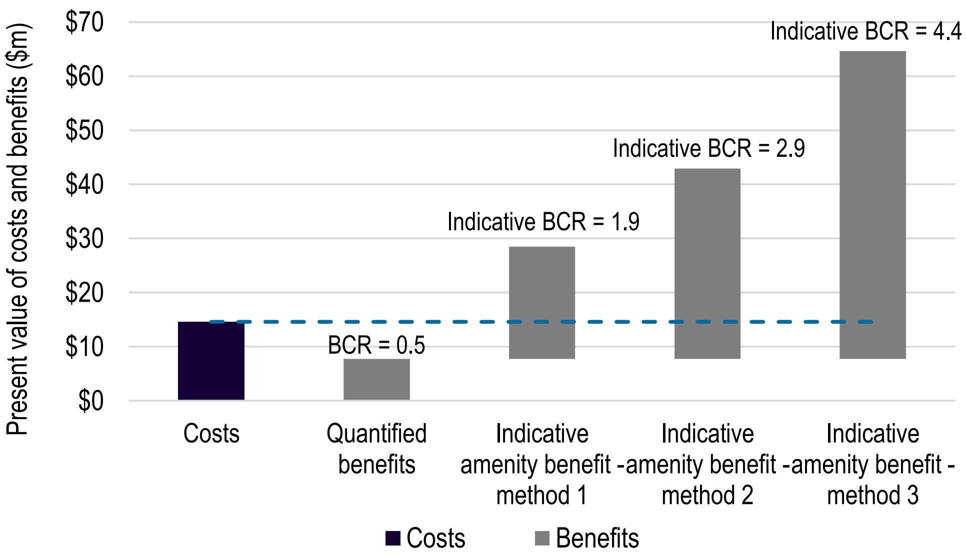
— Method 2: using the average of the property uplift percentages identified in Western Australia and Canberra (2.6% and 2.9% respectively, giving an average of 2.75%) as a proxy for the amenity value of undergrounding to local residents, and applying this uplift to the median metropolitan Melbourne house price of $820,000 to give an amenity benefit of almost $22,500 per household.

— Method 3: proxying the amenity value of undergrounding to local residents as 2.75% of the median house price in eastern and south-eastern Melbourne (and which is therefore more reflective of the exemplar modelled in this study), giving an amenity benefit of just over $36,000 per household.

If we apply each of these estimates to the 1,572 residential customers served by overhead connections in our exemplar, we calculate further amenity benefits of $21 million to $57 million for our exemplar.

Noting the need for caution, including these indicative amenity benefits suggests very significant net benefits from undergrounding (Figure 4.1).

Figure 4.1 Present value of costs and benefits of undergrounding using a 4% discount rate, including indicative estimates of amenity benefits



Source: ACIL Allen analysis

This finding is somewhat supported by the observation that the Western Australian, South Australian and Northern Territory governments have supported electricity undergrounding over many decades (Box 4.1).

From 1995 to 2012 the Victorian Government operated an undergrounding policy, the Powerline Relocation Scheme, until it was discontinued as funding was reprioritised to support bushfire prevention by electricity networks in the wake of the 2009 Black Saturday fires.[xxxvii] Under this policy, the Victorian Government would provide up to 50% of the cost of undergrounding for projects that met the application criteria, and local governments and electricity distribution companies made co-contributions.[xxxviii] Additionally, since the 1990s it has been standard for all new residential developments in Victoria to have underground power supply.[xxxix]

Overall, if the amenity benefits of undergrounding are significant in Victoria, these investments could be cost-effective in a range of locations, and so prove a practical way for electricity distribution networks to adapt to climate change. Importantly, undergrounding also complements the objectives of many local governments to increase tree canopy, which is itself a valuable adaptation to a warming climate.

Box 4.1 State and territory undergrounding policies

Western Australia

The Western Australian Government established the State Underground Power Program (SUPP) in 1996, largely in response to major power outages from a 1994 storm. The SUPP has undergrounded over 100,000 properties over multiple funding rounds.

A 2011 review of the SUPP by the Economic Regulation Authority of WA found that the program had delivered net benefits to that point, with the largest single benefit category being improved amenity value for home-owners ($749 million in benefits out of a total of $817 to $858 million).

The Economic Regulation Authority of WA recommended that the State Government reduce contributions to projects in high-income areas, as most of the benefits are captured by relatively wealthy home-owners. But it also recommended that the project be continued.

From 2024 the WA Government will implement a re-branded Targeted Underground Power Program, with a greater focus on areas with ageing network infrastructure, and on lower-income areas that have been under-represented in the program to date.

South Australia

The South Australian Government established the Power Line Environment Committee in 1990, bringing together energy network, transport, local government, tourism and community interests to coordinate undergrounding projects. The projects were funded through mandatory contributions from the monopoly distribution network operator, and project-specific contributions from local governments.

Unlike the SUPP, the Power Line Environment Committee has focused on undergrounding major transport routes and community and tourism hubs, rather than general residential areas.

The Power Line Environment Committee has delivered $231 million of projects in a mix of metropolitan and regional locations from program start until 2019-20.

Northern Territory

New residential developments in the Northern Territory have been required to have underground power since the late 1970s, reflecting in part the impacts of Cyclone Tracy in 1974.

In addition the NT Government has funded a range of undergrounding programs, including:

— supply to nine Darwin schools in 2019

— $60 million in 2022 to underground targeted parts of the Darwin high voltage network.

Source: WA Government, State Underground Power Program 2022-23, https://www.wa.gov.au/government/document-collections/state-underground-power-program-2022-23; Essential Services Commission of South Australia, Power Line Environment Committee resources, https://www.escosa.sa.gov.au/industry/electricity/plec/plec-resources; NT Government, Budget 2022: undergrounding high voltage power network begins, https://ntrebound.nt.gov.au/news/2022/budget-2022-undergrounding-high-voltage-power-network-begins; Power and Water Corporation, Undergrounding power supply to Darwin schools, https://www.powerwater.com.au/about/projects/current-projects/undergrounding-power-supply-to-darwin-schools.

4.3 Interaction with network re-investment

Our CBA assumes that the existing overhead network infrastructure is of mixed age and is replaced periodically over its expected life of 50 years. This gradual rate of replacement reduces the capital cost of network infrastructure in the base case in present value terms. However, if network re-investment is required more urgently than we have assumed, the cost of base case investment increases in present value terms and the case for investing in undergrounding or insulated cable is strengthened.

Urgent network re-investment might be required if a particular part of the network has much older infrastructure than the network as a whole. If, for example, an entire network area's infrastructure has aged to the point where it needs to be replaced within ten years, using a 4% discount rate the BCR:

— of undergrounding improves from 0.53 to 0.72 (excluding the indicative amenity benefits estimated in section 4.2)
— of insulated cable improves from 1.2 to 2.3.

This indicates a good case for upgrading infrastructure to be more climate resilient at end-of-life, rather than simply replacing it like-for-like. However, we note that the age of infrastructure in any given area will generally vary due to ongoing maintenance and replacement (for example, due to storms, vehicle impacts or asset failures), and it will be relatively uncommon to find specific areas with distinctly ageing infrastructure that requires widespread and urgent replacement.

Another circumstance that could improve the economics of undergrounding or insulated cable is if rapid increases in electricity demand outstrip the capacity of existing network assets, and so drive significant re-investment. Such rapid increases in electricity demand were last seen in the late-1990s and early-2000s when Australian households and businesses rapidly installed air-conditioning with associated growth in peak summer demand. (Since the late-2000s peak electricity demand growth has generally been muted, largely because of improved thermal efficiency of homes, improving energy efficiency of appliances and rapid uptake of rooftop solar photovoltaic generation.)

While peak demand growth has been muted in recent years, there is a high likelihood of significant increases in demand throughout Victoria's electricity distribution networks over coming decades from two main sources: electric vehicles and the electrification of household heating.[xl] Electric vehicles represent a potential step-change in household electricity demand and will increase loads at the low and high voltage level across all distribution networks. And the electrification of household heating could see winter electricity demand peak at higher levels as increasing gas prices cause households to switch their heating from gas to reverse-cycle air-conditioners.

The scale and speed of these sources of demand growth is highly uncertain, and there is significant potential for smart demand management to reduce the need for network investment to accommodate these loads. However, the potential need to accommodate electric vehicles and heating electrification also creates an opportunity to better adapt these networks to the effects of climate change by insulating or undergrounding power lines where reinvestment is required.

4.4 Potential Victorian Government actions to facilitate undergrounding

The lack of widespread undergrounding in Victoria could suggest that households and local governments do not value the benefits sufficiently to pay for them. Or, more likely, it reflects that undergrounding is a complex exercise requiring coordination across a range of beneficiaries – including local home-owners and businesses, visitors, local governments, electricity distribution network businesses and state government entities – and that raises difficult questions about who should pay. This complexity acts as a major barrier to undergrounding existing electricity infrastructure. The complexity of undergrounding is demonstrated by a recent case study involving the Bayside City Council, which covers inner south-east bayside suburbs of Melbourne such as Brighton and Sandringham (Box 4.2).

This complexity, and the successful experience of the Western Australian and South Australian governments in coordinating the multiple parties involved in undergrounding projects (see Box 4.1), suggests an important coordination role for the Victorian Government to facilitate undergrounding.

Box 4.2 Bayside City Council's undergrounding power policy

During 2022 Bayside City Council developed a draft policy on undergrounding power lines. This policy set out the council's in-principle support for undergrounding, and noted a range of benefits including:

— aesthetic improvements to the streetscape and increased tree coverage
— improved power reliability
— reduced costs to maintain tree clearances around power lines
— removal of potential traffic hazards.

The council also surveyed residents to obtain their views and found that 81% per cent of residents surveyed were in favour of undergrounding.

Despite this support, the draft policy was not adopted by Council due to disagreements over the best approach to funding projects. The four options considered in the draft policy were:

— direct funding as part of council-funded capital works
— Victorian Government grants (noting that such a program is not presently in place)
— increased rates for benefiting home-owners
— direct payment by benefiting home-owners through negotiation with electricity networks.

Source: Bayside City Council, Undergrounding powerlines, https://yoursay.bayside.vic.gov.au/powerlines

Our analysis highlights a few principles and priorities for future Victorian Government actions to support undergrounding:

— There is a significant knowledge gap in Victoria on the amenity benefits of undergrounding. The Victorian Government could support comprehensive studies of this value, such as through hedonic pricing or contingent valuation methodologies. If these studies confirm the broad findings of past Western Australian and Canberran studies, the case for undergrounding in primarily residential areas in Victoria would be greatly strengthened.

— When amenity benefits are included, the majority of benefits of undergrounding accrue to home-owners.

— Though the majority of benefits of undergrounding accrue to home-owners, other parties do benefit:

  – People who work in the area or who visit will benefit from improved amenity.
  – Electricity network businesses benefit from undergrounding through reduced vegetation management expenditure and reduced capital expenditure on replacing ageing assets (as undergrounding delivers an entirely new set of assets).
  – Local governments benefit from undergrounding through reduced vegetation management expenditure.
  – To the extent that undergrounding reduces the health impacts of future heatwaves and the human impact of some traffic crashes, the primary health system will experience lower costs.

— Systems and processes for undergrounding can be standardised across multiple local governments, to simplify processes for electricity distribution network businesses (who work across many local government areas) and deliver efficiency benefits from avoiding individual local governments having to 'reinvent the wheel'.

4.5 Using real options to reduce uncertainty on costs and benefits

While the results in chapter 3 do not indicate that investment in electricity distribution networks is generally a cost-effective way to address the effects of extreme wind in an urban supply area, a 'real options' perspective (see Box 4.3) highlights several areas where further consideration of these options will be valuable.

Box 4.3 Real options analysis

Real options is an analytical framework that seeks to accommodate the effects of uncertainty on economic decision-making and recognises that deferring or staging major investment decisions to gain more information can create benefits that are not captured in a static scenario analysis. For example:

If a company committed $10 million to an investment with a 50% probability of returning $20 million and a 50% probability of returning nothing, the expected value of the investment is zero.

However, if that same company committed $2 million to facilitate the same investment of $10 million quickly if market circumstances moved in a favourable direction it would have a:

— 50% probability of incurring a loss of $2 million, in the event that market circumstances were not favourable and the investment was not taken
— 50% probability of incurring a benefit of $8 million, in the event that market circumstances were favourable and the investment was taken.

The probability-weighted value of the total investment taking a real options perspective is $3 million, compared to $0 under a static scenario approach.

Source: ACIL Allen analysis

The key factors that could increase the value of the analysed adaptation measures under a real options perspective is where information increases over time to support more targeted investment decisions. In turn, the most valuable information will relate to the most uncertain cost or benefit categories, such as:

— the amenity value of undergrounding investment (not quantified in this study, but indicatively estimated in section 4.1 above)
— the effectiveness of insulated cable in preventing power outages in major storm events
— increased temperatures and the effect of tree canopy on health costs
— increased impacts of extreme wind on network outages
— the cost premium of grid-forming inverters over grid-following inverters.

In the case of the amenity benefit of undergrounding, investing a small amount of money to gain better information on these benefits would have significant value (as discussed in section 4.2). If studies establish that the amenity benefits of undergrounding are large, the relatively small amount of money invested in these studies could potentially support investment to unlock multiple billions of dollars of benefits.[9]

In the case of insulated cable's effectiveness in major storm events, as discussed in section 4.1, there may be scope for further investigation of the effectiveness of insulated cable to provide valuable information to support future decisions on the use of this adaptation measure.

Further monitoring for improvements in climate data would be beneficial to refine the case for all adaptation measures. Refined projections on the frequency and severity of extreme wind would reduce the uncertainty around the potential benefits of these measures.

Though the cost premium for grid-forming inverters relative to grid-following inverters was projected for this study to be too high for them to deliver a net benefit from reduced power outages, it is possible that their cost may fall faster than assumed in this analysis. Monitoring trends in the cost of this equipment could highlight where the case for investment has improved, and updated cost-benefit analysis may be justified.

[9] Gross amenity benefits of about $13,000 per household translate to net benefits of over $9,000 per household (reflecting the cost of undergrounding net of the other benefits identified in this study). If this benefit translated to half of Victoria's 2.4 million occupied private dwellings, the aggregated net benefits would exceed $11 billion.

4.6 Methodological lessons for climate adaptation analyses

Cost-benefit analysis of climate adaptation measures for infrastructure must address a number of complexities and uncertainties. This study is no exception, and our experience in analysing adaptation measures to combat the effects of extreme wind on the electricity distribution network is likely to have lessons for analyses of other climate hazards and other infrastructure sectors.

Some particularly difficult methodological issues we have encountered in this study include:

— the uncertainty of climate change impacts, and sensitivity of these impacts to assumptions on global emissions concentration pathways

— the interaction between adaptation measures as both mitigating the impacts of climate change, but also contributing to climate change through embodied emissions

— the sensitivity of the benefits of adaptation measures to the scale at which they are applied

— the risk that adaptation measures will reduce the impact of the identified hazard (extreme wind), but cause maladaptations that create new risks to the operation of the infrastructure

— the difficulty of estimating some particularly uncertain costs or benefits.

Uncertainty of climate change impacts

Climate change will have long-lasting and uncertain impacts on infrastructure, and so these impacts are particularly difficult to quantify. Even where climate change has a created a clear trend, such as towards increasing average temperatures or bushfire risk, there is significant year-to-year variability in outcomes around this trend and uncertainty in terms of both the probability and severity of extreme weather events in any given year.

These uncertainties have been particularly acute for this analysis due to our focus on extreme wind. Compared to extreme heat or bushfires, where there is a clear relationship between climate drivers and outcomes, the effect of climate change is particularly uncertain and location-specific. As noted in section 2.4.1 (page 23), the *Victorian Climate Projections* forecast declining severity of extreme wind in some Victorian locations, and increasing severity in others.

In our exemplar, these projections indicated increasing severity and frequency of extreme winds under a moderate emissions trajectory (RCP 4.5, broadly consistent with strong global action to curb greenhouse gas emissions) but, counter-intuitively, no clear impact under a high emissions trajectory (RCP 8.5).

This highlights the uncertainty of extreme wind outcomes, and a need for caution in interpreting the results of this study. We used sensitivity analysis to examine the possibility that climate change will have a much lower impact on the severity and frequency of extreme wind than assumed in our core assumptions.

Impact of adaptation measures on climate change

Several of our adaptation measures created material embodied emissions through investment in new infrastructure (the undergrounding and insulated cable scenarios), or through replacing large mature trees with smaller trees (the tree replacement scenario). This illustrates a broader challenge in adapting infrastructure to climate change – the act of replacing or upgrading infrastructure will typically create embodied emissions and exacerbate the problem the investments are responding to.

Our analysis of embodied emissions is specific to the infrastructure analysed and indicates that, broadly speaking, the embodied emissions of our proposed adaptation measures are not sufficiently large to prevent their adoption (see section 2.3.3). This finding may not translate to other infrastructure types or other adaptations. Electricity distribution infrastructure has a specific mix of materials that differs to that used in, for example, roads, bridges, dams or even electricity transmission infrastructure. For example, wooden poles and all-aluminium conductors are common in electricity distribution networks, whereas electricity steel towers and steel-reinforced aluminium conductors are common in electricity transmission networks.

Therefore it is important that case-specific assessments of embodied emissions are undertaken for other infrastructure sectors and adaptation measures.

Scale of application

Our approach to estimating the value of customer reliability reflects the fact that some benefits of electricity network adaptation depend on how widely the measures are implemented. Strictly speaking, the broader social benefits that arise from continuity of supply to transport infrastructure and other essential services are small if the measure is implemented only in our single hypothetical exemplar, but these benefits will be much larger if the measure were to be implemented widely. This uncertainty was addressed by assessing outcomes under a sensitivity with a social multiplier applied to the value of avoided outages (section 3.3).

Other infrastructure adaptation studies could face similar issues. The effectiveness of adaptation measures to improve the resilience of network-based infrastructure, such as transport or telecommunications infrastructure for example, is particularly likely to be sensitive the scale at which these measures are applied. Studies of such infrastructure that adopt a case study approach may need to consider the effects of applying measures widely, as we have done for this study through the social benefits multiplier.

Maladaptation risks

In analysing measures that can adapt electricity distribution infrastructure to reduce the risk of extreme wind, we also considered the possibility that this could create exposure to new risks (see the discussion in section 2.4.1 on page 27). In particular, some of these risks are themselves affected by climate change, such as the risk of flooding or extremely dry soil causing damage to underground cables.

Our analysis did not indicate that maladaptation risks were material to the performance of the infrastructure considered in this study. However, this may not be true of other infrastructure adaptations in other sectors, and it is important that maladaption risks are carefully considered on a case-by-case basis in infrastructure adaptation analyses.

Uncertain cost or benefit categories

Many cost-benefit analyses must estimate highly uncertain costs or benefits, but these difficulties can be particularly acute for infrastructure climate adaptation analyses. This is because of both the long duration over which costs and benefits of long-lived infrastructure must be assessed, and the particularly uncertain nature of climate impacts (discussed above on page 47).

In addition to these effects, which are likely to be common to most infrastructure adaptation studies, this study required estimation of several particularly uncertain cost and benefit categories.

— The amenity benefits of undergrounding are potentially large but highly uncertain. As illustrated in Figure 4.1, these benefits could plausibly move undergrounding from a BCR of well below one to 2 or more. As is discussed in section 2.4.4, the approach we took to manage this uncertainty was to exclude these potential benefits from the core CBA but present indicative amenity benefits to illustrate their importance.
— Estimating the number of trees that were sufficiently large and close to power lines to require replacement under the tree replacement scenario required visual analysis of randomly sampled areas from which our exemplar sample was drawn. Such visual inspection is

inherently subjective and uncertain, as specialised arboreal assessment or on-site inspection was beyond the scope of this analysis (our assessment was done using Google Maps Street View). Changes in the areas sampled could also lead to variations in results.

— Assumptions around the future decrease in the cost premia applying to grid-forming inverters relative to typical grid-following inverters are particularly uncertain due to the rapid change in this technology, particularly for small-scale inverters. It is possible that the cost premium could decline to a point where this technology becomes the default application for small-scale solar and battery inverters. However, forecasting the probability or potential timing of such a point is inherently difficult. This uncertainty is best managed through a real options approach involving a 'watching brief' on cost trends for this technology (see section 4.5), rather than an early commitment to investment.

Translating assumptions to other studies

In many cases the sources used in our study reflect costs and benefits that are specific to electricity distribution infrastructure and the effects of extreme wind, while in other cases a broad range of studies will be able to use similar assumptions. These similarities and differences are set out in Box 4.4.

Box 4.4 Extending ACIL Allen's methodology to other infrastructure adaptation cost-benefit analyses

Discount rates

We adopted standard Victorian discount rates for this study, which would be common to a range of Victorian infrastructure CBAs. However, ACIL Allen notes that the NSW Government has recently issued new guidance on discount rates to reflect lower interest rates over recent years, and it is possible that the Victorian Government will update its guidance in future.

Climate data

Climate impacts on extreme wind vary by location and are subject to some uncertainty. We used the *Victorian Climate Projections* to estimate wind impacts for our exemplar area, and this study indicates that extreme wind events could decrease in some Victorian locations. This means that the findings for our exemplar will not necessarily extend to other locations.

Value of power outages

We used network regulatory information notices collated by electricity distribution networks and published by the Australian Energy Regulator (AER), and values of customer reliability (VCR) developed by the AER. While the VCR analysis is relevant to all electricity outages, including those arising due to issues in the generation or transmission of power, our detailed analysis of the causes and durations of outages is specific to electricity distribution networks.

Health benefits from increased tree canopy

We used analysis developed by the NSW Government on the value of 'green infrastructure' to calibrate costs and benefits from changes in tree canopy. The parameters identified in that study and used here would be of relevance to a range of projects that affect tree canopy, including clearing canopy to make space for new infrastructure, or developing new parkland to mitigate urban heat island effects.

Reduced traffic crash impacts

We calibrated the cost of traffic crashes involving power poles based on crash statistics from VicRoads and crash cost estimates from the Australian Transport Assessment and Planning guidelines. These estimates would not typically be needed for an energy sector analysis, but may be relevant to analyses of other infrastructure, particularly transport infrastructure.

Capital expenditure

Our capital expenditure estimates were bespoke and specific to the adaptation measures modelled. However, urban electricity distribution infrastructure is relatively standardised across Australia, and our cost estimates could inform other studies involving similar infrastructure in other jurisdictions.

Operating expenditure

Our operating expenditure estimates were bespoke and reflect the specific infrastructure modelled. However, urban electricity distribution infrastructure is relatively standardised across Australia, and so our estimates could be used to inform analyses of urban distribution infrastructure in other jurisdictions. Similarly, our vegetation management costs could be informative for other studies of areas similar to the exemplar, that is, a well-treed Australian urban area with primarily overhead electricity distribution infrastructure.

Embodied emissions

Our embodied emissions estimates were bespoke and specific to the adaptations modelled. However, urban electricity distribution infrastructure is relatively standardised across Australia, and so these estimates could inform other studies involving similar infrastructure in other jurisdictions.

We used the recent (April 2023) guidance from the NSW Government on carbon prices, which builds on current day prices in the European Union Emissions Trading Scheme. However, there are a range of other possible sources to benchmark carbon prices for infrastructure CBAs.

Sources: NSW Government 2023, TPG23-08 NSW Government Guide to cost-benefit analysis, Technical note to TPG23-08: Carbon value in cost-benefit analysis, https://www.treasury.nsw.gov.au/sites/default/files/2023-03/20230302-technical-note-to-tpg23-08_carbon-value-to-use-for-cost-benefit-analysis.pdf; CSIRO, GenCost project data, https://data.csiro.au/collection/csiro:44228; Infrastructure and Transport Ministers 2020, Australian Transport Assessment and Planning Guidelines: PV5 environmental parameter values, https://www.atap.gov.au/parameter-values/environment/index; Economic Connections 2017, Cost of Road Trauma in Australia, https://www.aaa.asn.au/wp-content/uploads/2018/03/AAA-ECON_Cost-of-road-trauma-summary-report_Sep-2017.pdf; Australian Government, Australian Road Deaths Database, https://www.officeofroadsafety.gov.au/data-hub/fatalities-data#accordion-58; Australian Government, Severe Injuries Dashboard, https://www.officeofroadsafety.gov.au/data-hub/serious-injuries-data#accordion-76; VicRoads, Crash statistics, https://www.data.vic.gov.au/data/dataset/crash-stats-data-extract.

Endnotes

[i] Infrastructure Victoria 2021, *Victoria's infrastructure strategy 2021-2051*, https://www.infrastructurevictoria.com.au/report/1-3-embed-resilience/.

[ii] Victorian Government, *Electricity distribution network resilience review*, https://www.energy.vic.gov.au/about-energy/legislation/regulatory-reviews/electricity-distribution-network-resilience-review.

[iii] Energy Networks Australia 2022, *Electricity networks: a guide to climate change and its likely effects*, https://www.energynetworks.com.au/resources/reports/2022-reports-and-publications/electricity-networks-a-guide-to-climate-change-and-its-likely-effects/.

[iv] Infrastructure Victoria, *Victoria's infrastructure strategy*, https://www.infrastructurevictoria.com.au/project/30-year-strategy/.

[v] Infrastructure Victoria 2021, *Victoria's infrastructure strategy 2021-2051*, https://www.infrastructurevictoria.com.au/report/1-3-embed-resilience/.

[vi] Victorian Government, *Electricity distribution network resilience review*, https://www.energy.vic.gov.au/about-energy/legislation/regulatory-reviews/electricity-distribution-network-resilience-review.

[vii] Energy Networks Australia 2022, *Electricity networks: a guide to climate change and its likely effects*, https://www.energynetworks.com.au/resources/reports/2022-reports-and-publications/electricity-networks-a-guide-to-climate-change-and-its-likely-effects/.

[viii] IPCC 2021, *Summary for policymakers* in *The physical science basis: contribution of working group I to the sixth assessment report of the Intergovernmental Panel on Climate Change*, https://www.ipcc.ch/sr15/chapter/spm/, p. 4 and p. 14.

[ix] Victorian Government and CSIRO, *Victorian climate projections 2019*, https://www.climatechangeinaustralia.gov.au/en/projects/victorian-climate-projections-2019/.

[x] Stern 2006, *The economics of climate change: the Stern Review*, https://www.lse.ac.uk/granthaminstitute/publication/the-economics-of-climate-change-the-stern-review/.

[xi] See for example Arrow et al 2014, *Should governments use a declining discount rate in project analysis?, Review of Environmental Economics and Policy 8(2)* (2014): 145-162.

[xii] Department of Treasury and Finance, *Economic evaluation for business cases: technical guidelines*, August 2013, Table 7.

[xiii] Kuleshov, de Hoedt, Wright and Brewster, *Thunderstorm distribution and frequency in Australia*, *Aust. Met. Mag. 51* (2002) 145-154.

[xiv] Wood, Dundas and Percival 2019, *Keep calm and carry on: managing electricity reliability*, https://grattan.edu.au/wp-content/uploads/2019/02/914-Keep-calm-and-carry-on.pdf, p. 10; Australian Energy Market Commission Reliability Panel 2019, *Definition of unserved energy – final report,* https://www.aemc.gov.au/sites/default/files/2019-07/Final%20report%20-%20Definition%20of%20unserved%20energy.pdf, p. 51.

[xv] Australian Energy Market Operator 2022, Integrated System Plan: Inputs, assumptions and scenarios workbook, https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/inputs-assumptions-and-scenarios-workbook.xlsx?la=en.

[xvi] Australian Bureau of Statistics 2019, *Household and family projections*, https://www.abs.gov.au/statistics/people/population/household-and-family-projections-australia/latest-release.

[xvii] Australian Energy Regulator 2022, *AusNet Services – cost pass through – October 2021 storm*, https://www.aer.gov.au/system/files/AusNet%20Services%20-%20Attachment%201%20-%20Build%20up%20of%20costs%20-%20Public.xlsx.

[xviii] Australian Energy Regulator *Economic benchmarking regulatory information notices – operating environment*; various networks, available at: https://www.aer.gov.au/networks-pipelines/performance-reporting.

[xix] Bureau of Meteorology, data requested via *Weather station directory*, http://www.bom.gov.au/climate/data/stations/.

[xx] Victorian Government and CSIRO, *Victorian climate projections 2019*, https://www.climatechangeinaustralia.gov.au/en/projects/victorian-climate-projections-2019/.

[xxi] Clarke et al. 2019, *Victorian climate projections 2019 technical report*, https://www.climatechangeinaustralia.gov.au/en/projects/victorian-climate-projections-2019/vcp19-publications/.

[xxii] Australian Energy Regulator, *Values of customer reliability*, https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/update-0.

[xxiii] Reichl, Schmidthaler and Schneider, *The value of supply security: the costs of power outages to Austrian households, firms and the public sector*, Energy Economics 36 (2013) 256-261.

[xxiv] Reichl and Schmidthaler, *Methodology, assumptions, and an application of blackout-simulator.com*.

[xxv] The Living Conservancy and Resilient Melbourne 2019, *Living Melbourne: our metropolitan urban forest*, https://livingmelbourne.org.au/wp-content/uploads/2022/10/Strategy_online.pdf, p. 50.

[xxvi] See for example City of Greater Geelong 2014, *Urban forest strategy 2015-2025*, https://www.geelongaustralia.com.au/common/public/documents/8d30153dfee2a6c-Urban%20Forest%20Strategy.pdf.

[xxvii] Calculated based on the total population in the United Energy service area divided by the number of residential customers for that network, based on ACIL Allen of local government area population estimates and Untied Energy regulatory information notices.

[xxviii] NSW Government, 2022 *Interim framework for valuing green infrastructure and public spaces*, NSW Department of Planning and Environment, p. 38.

[xxix] NSW Government, 2022 *Interim framework for valuing green infrastructure and public spaces*, NSW Department of Planning and Environment, p. 39.

[xxx] The Living Conservancy and Resilient Melbourne 2019, *Living Melbourne: our metropolitan urban forest*, https://livingmelbourne.org.au/wp-content/uploads/2022/10/Strategy_online.pdf, p. 50.

[xxxi] Victorian Government 2019, *Melbourne metropolitan region urban vegetation cover 2018*, https://www.planning.vic.gov.au/policy-and-strategy/planning-for-melbourne/plan-melbourne/cooling-greening-melbourne/mapping-and-analysis-of-vegetation,-heat-and-land-use, p. 7.

[xxxii] See for example Astell-Burt and Feng 2019, *Association of urban green space with mental health and general health among adults in Australia*, *JAMA Network Open* 2(7): e198209, https://doi:10.1001/jamanetworkopen.2019.8209.

[xxxiii] Energy Safe Victoria, *Electrical safety performance reports* (various years), https://www.esv.vic.gov.au/about-us/our-organisation/reports/electrical-safety-performance-reports.

[xxxiv] Mooney, Webb and Mott indicate that in their article *Managing bird interactions with power distribution assets in Australia* that there is “no systematic measuring of the impact on bird populations of power transmission and distribution lines and their poles in Australia”: p. 227 in Martin, Lopez, Sousa and Barros (2022), *Wildlife and power lines: guidelines for preventing and mitigating wildlife mortality associated with electricity distribution networks*.

[xxxv] See for example Loss, Will and Marra (2014), *Refining estimates of bird collision and electrocution mortality at power lines in the United States*, PLoS ONE 9(7): e101565, https://doi.org/10.1371/journal.pone.0101565.

[xxxvi] See for example GHD 2021, *ISP transmission cost database*, https://aemo.com.au/-/media/files/major-publications/isp/2021/transmission-cost-database---ghd-report.pdf?la=en.

[xxxvii] Victorian Government 2008, *Powerline relocation: an assistance scheme for local areas*, https://vgls.sdp.sirsidynix.net.au/client/search/asset/1017954.

[xxxviii] Victorian Government 2008, *Powerline relocation: an assistance scheme for local areas*; Powerline Bushfire Safety Taskforce 2011, *Final report*, p. 122, https://www.energy.vic.gov.au/__data/assets/pdf_file/0035/594098/Powerline-Bushfire-Safety-Taskforce-Report.pdf.

[xxxix] Energy Safe Victoria 2022, *Greenfield underground residential distribution: cable jointing research project – findings report*, https://www.esv.vic.gov.au/sites/default/files/2022-12/Greenfield-Underground-Residential-Distribution-URD-%E2%80%93-Cable-Jointing-Research-Project_Final-Report-.pdf, p. 6.

[xl] Victorian Government 2022, *Gas substitution roadmap*, https://www.energy.vic.gov.au/__data/assets/pdf_file/0025/586411/Victorias-Gas-Substitution-Roadmap.pdf, p. 30; Infrastructure Victoria 2022, *Towards 2050: gas infrastructure in a net zero emissions economy*, https://www.infrastructurevictoria.com.au/wp-content/uploads/2022/02/Towards-2050-Gas-infrastructure-in-a-net-zero-emissions-economy_FINAL-REPORT.pdf, p.73.

Melbourne
Suite 4, Level 19; North Tower
80 Collins Street
Melbourne VIC 3000 Australia
+61 3 8650 6000

Sydney
Suite 603, Level 6
309 Kent Street
Sydney NSW 2000 Australia
+61 2 8272 5100

Brisbane
Level 15, 127 Creek Street
Brisbane QLD 4000 Australia
+61 7 3009 8700

Canberra
Level 6, 54 Marcus Clarke Street
Canberra ACT 2601 Australia
+61 2 6103 8200

Perth
Level 12, 28 The Esplanade
Perth WA 6000 Australia
+61 8 9449 9600

Adelaide
167 Flinders Street
Adelaide SA 5000 Australia
+61 8 8122 4965

ACIL Allen Pty Ltd
ABN 68 102 652 148

acilallen.com.au