CitiPower

RIT-D Russell Place Zone Substation

Draft Project Assessment Report

December 2019

Contents

1 Overview

This draft project assessment report has been prepared in accordance with the Regulatory Investment Test for Distribution (**RIT-D**) requirements of the National Electricity Rules (**the Rules**)[1].

The purpose of this draft project assessment report is to consult on the credible options to address the identified need—namely, the increasing risks to safety and reliability of supply caused by the deterioration of the aged building and electrical assets at Russell Place (**RP**) zone substation that was built approximately 65 years ago.

Due to its location within the Melbourne CBD and the nature of the customers that zone substation RP supplies, CitiPower has determined that there are no credible non-network options that could address the energy at risk to defer or replace the proposed works. This determination is made under clause 5.17.4(c) and (d) of the NER. This determination was published in accordance with clause 5.17.4(d) on 07/10/2019 and no responses were received regarding this determination. In accordance with these provisions, CitiPower will not publish a non-network options report in relation to the proposed network need at RP zone substation and will proceed with the draft project assessment.

Based on the analysis presented in this report, the preferred option is to de-commission RP zone substation and convert the 6.6 kV network to 11 kV and establish additional high voltage (**HV**) 11 kV feeder links to transfer RP load to the new Waratah Place (**WP**) zone substation. Our economic assessment indicates that this option should be implemented as soon as practical for optimum benefit, at an estimated total direct capital cost of $12.57M ($2019)[2].

We now seek further feedback from stakeholders including registered participants, the Australian Energy Market Operator (**AEMO**), non-network providers, interested parties and persons on our demand side engagement register. Submissions are due by 17 January 2020.

We will consider all submissions received in response to this draft project assessment report before preparing a final project assessment report.

Should the preferred option have an estimated capital cost of less than $20 million, we may publish the final project assessment report within our Distribution Annual Planning Report (**DAPR**).[3]

1 Version 109 of the Rules, clause 5.17.4.

2 All financial values in this report are stated in real 2019 terms unless otherwise noted.

3 In accordance with clause 5.17.4(s) of the Rules.

2 Background

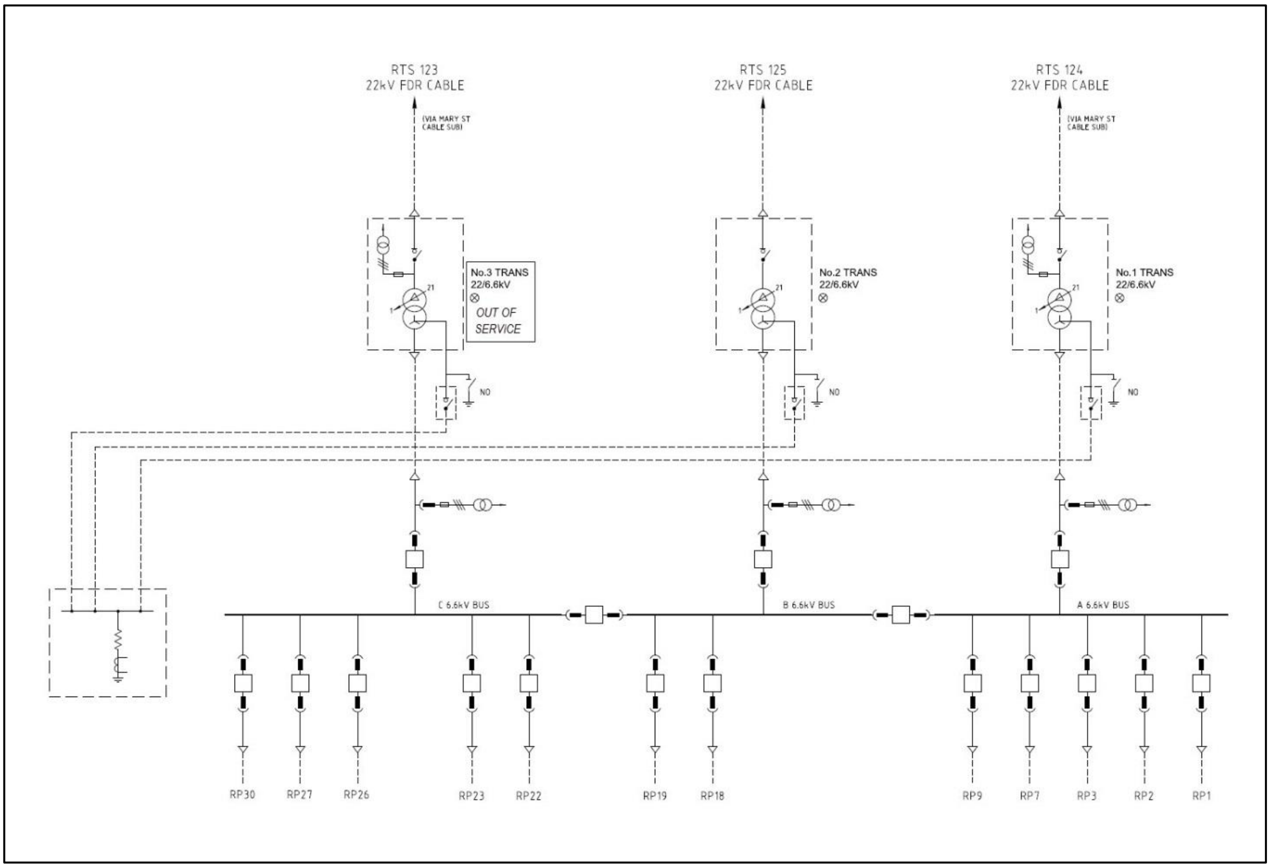
2.1 Zone substation configurations

RP zone substation was commissioned in the early 1950s as a 22 kV/6.6 kV station with three 10 MVA transformers supplied via underground 22 kV transmission cables from Richmond Terminal Station (**RTS**). Transformer number three is out of service due to a failure of the associated 22 kV transmission cable and as such the station rating is based on two transformers. The cable failure occurred in 2014 and, due to the high repair costs, returning this cable to service has been deferred till the assessment of the future of RP zone substation is determined.

The 22 kV cables from RTS are directly connected to each of the transformers and there is no 22 kV busbar or 22 kV transformer circuit breakers.

The transformers are connected to three 6.6 kV bus sections supplying twelve feeders. Figure 2.1 shows a single line diagram of the current arrangements at zone substation RP.

Figure 2.1 Zone substation RP single line diagram



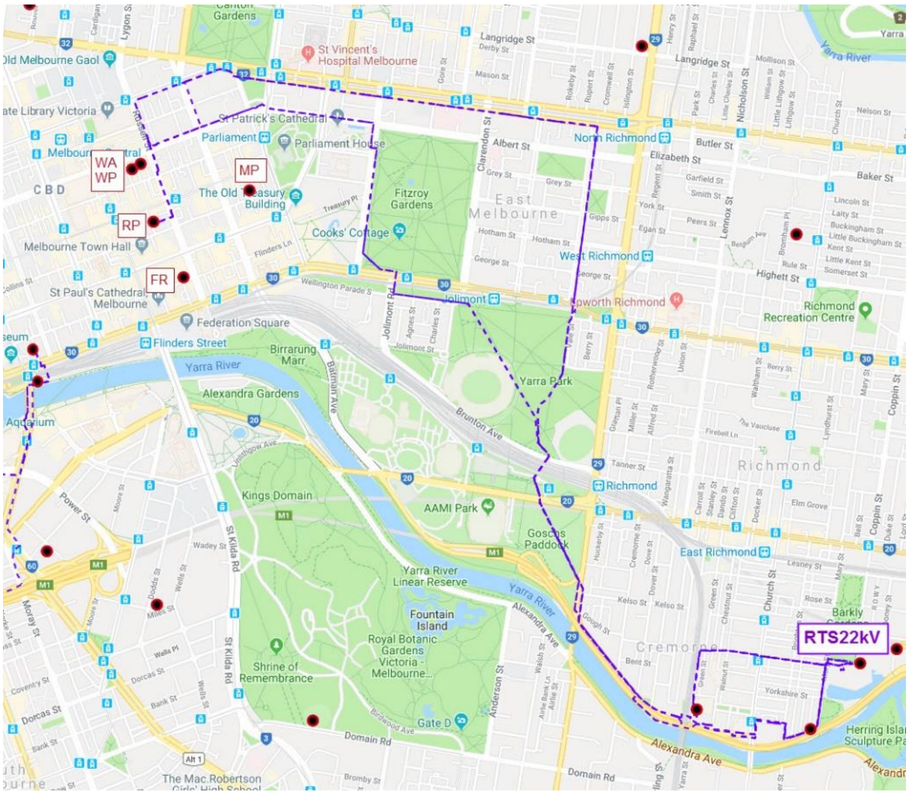
Zone substation RP is in the Melbourne CBD in a building basement in Russell Place and supplies an approximate two block area of the CBD. Electricity is supplied to 1,022 customers including 291 domestic, 722 commercial and 9 industrial customers including some high-profile sites such as the Melbourne Town Hall. Figure 2.2 shows the geographic area supplied by RP.

RP is located beneath a multi-story residential building and is integral to the foundation structure of that building.

Figure 2.2: Geographical area supplied by zone substation RP

The routes of the 22 kV transmission cables supplying RP from RTS are shown in Figure 2.3. The cables are approximately 5.8km in length and traverse major traffic routes, public parks and high-profile sporting facilities.

Figure 2.3: Route map of RP 22 kV transmission cables



2.2 Historical and forecast demand

Zone substation RP is forecast to remain a summer peaking zone substation. The load is significantly commercial with over 80% of customers in this category and most of the remaining demand is from residential customers being the next largest category at 18%.

The historical and forecast demand for summer and winter is shown in Figure 2.4 and Figure 2.5 respectively.

The CitiPower 2018 Distribution Annual Planning report identified that in 2023 there will be 2.8 MVA of load at risk and there are 221 hours for which it will not be able to supply all customers from the zone substation if there is a failure of one of the two transformers in service at RP. That is, it would not be able to supply all customers during high load periods following the loss of a transformer or 22 kV transmission cable.

Figure 2.4 Zone substation RP summer actual and forecast demand

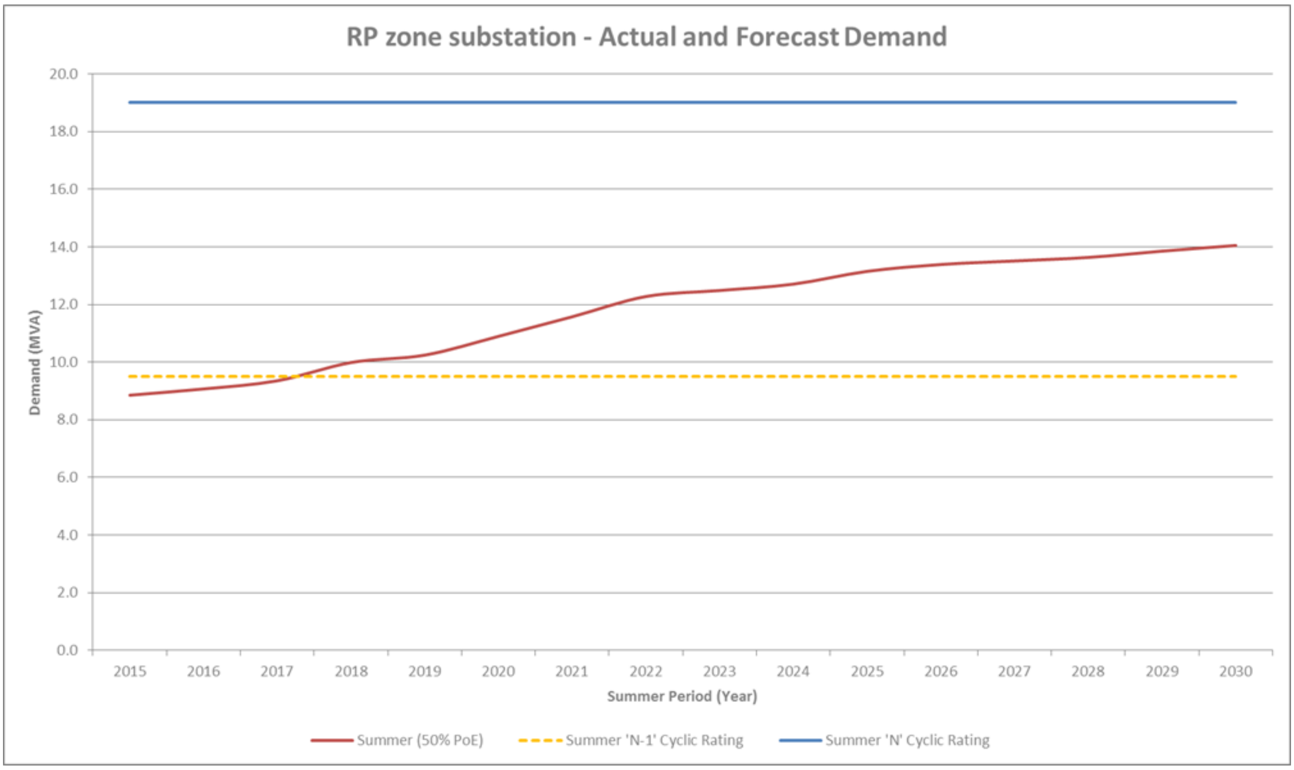
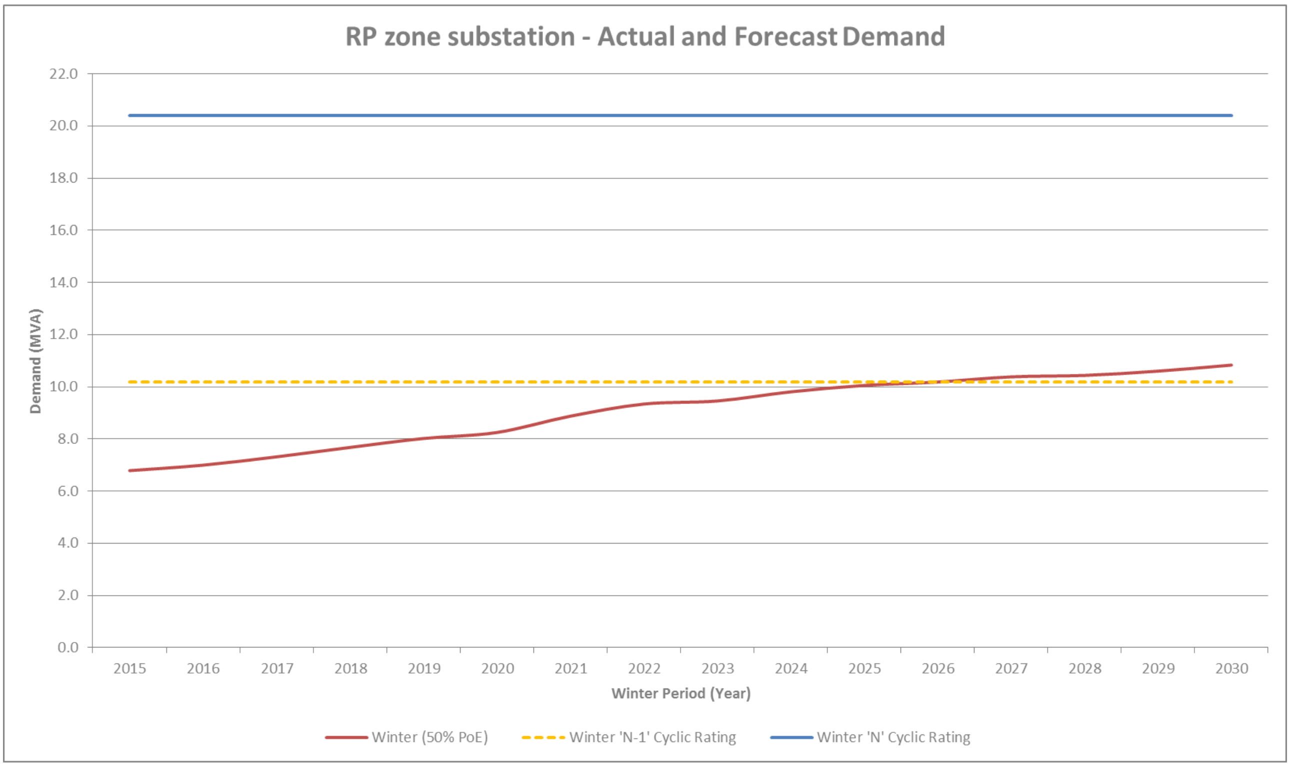


Figure 2.5 Zone substation RP winter actual and forecast demand



2.3 Load transfer capacity to adjacent zone substations

The 11 kV network surrounding the RP 6.6 kV network is supplied from nearby Flinders Ramsden substation (**FR**) McIlwraith Place substation (**MP**) and Celestial Avenue substation (**WA**). The new Waratah Place substation (**WP**) will also supply adjacent areas once it is commissioned into service in 2020. The geographic proximity of these substations is shown in Figure 2.2 and Figure 2.3.

There is limited transfer capacity available from this existing 11 kV network. During peak demand an estimated maximum transfer capacity of 4.0 MVA is available via a 6.6/11 kV auto transformer switching station to a standby 11 kV feeder. The standby feeder can only be used in an operational contingency response to partially mitigate the impact of an outage at zone substation RP.

The situation regarding asset condition at RP has been under review for several years with opportunities being preserved in other projects to provide future options. The design and construction of WP has been undertaken with consideration of providing an option to supply the load currently serviced by RP. It was determined prudent to delay earlier action for RP until WP was available as this new zone substation could provide a feasible option to address the identified need.

3 Identified need

3.1 Overview of the need for investment

Load at zone substation RP is forecast to exceed the station summer N-1 rating of 9.5 MVA in 2020 with load at risk increasing into the future. There is a need to meet the current demand and load growth in this area of the CBD with a secure supply. However, multiple assets including building structures, transformers, circuit breakers and auxiliary equipment are at the end of their service life, and the substation is supplied by aged and unreliable paper lead cables which are difficult to repair should a fault occur. These assets present an increasing operational and safety risk if they continue in service into the future.

As there is limited load transfer capability between zone substation RP and the adjacent substations, there is a risk that should a major outage occur at zone substation RP, customers will be left without electricity for a sustained period as we will be unable to restore supply to all customers until repairs are made and existing assets returned to service or replaced. In addition, in the event of a catastrophic failure of a transformer or circuit breaker, there is a risk of serious injury to staff and major damage to plant and buildings. Significant time may be required to restore or replace assets to enable restoration of supply. The basement location increases the consequence of a catastrophic failure and while the likelihood is low, there is potential to cause damage and/or disruption to the CBD buildings above and adjacent to the substation.

The identified need, therefore, is to address the increasing risks to safety and reliability of supply associated with the deterioration of the assets at zone substation RP. This ensures we continue to comply with the following:

- section 98 of the Electricity Safety Act[4]
- clauses 3.1 and 5.2 of the Victorian Electricity Distribution Code[5]

Section 3.2 below provides an overview of our approach to assessing asset condition and risk. Sections 3.3 to 3.7 then provide further information on the condition of the plant at zone substation RP, and the need to address the risks associated with the deteriorating condition of these assets.

3.2 Our approach to assessing asset condition and risk

We apply the condition-based risk management (**CBRM**) methodology to certain plant-based asset classes, namely transformers and HV circuit breakers. The CBRM model is an asset risk assessment algorithm that considers a range of inputs including:

- asset condition assessment data, such as transformer oil condition
- environmental factors, such as whether the assets are located indoors or outdoors, or coastal areas
- operating factors, such as the load utilisation, frequency of use and load profiles that the asset is supplying.

[4] Under section 98 of the Electricity Industry Safety Act, CitiPower (as a major electricity company) must design, construct, operate, maintain and decommission its supply network to minimise as far as practicable:

- the hazards and risks to the safety of any person arising from the supply network; and
- the hazards and risks of damage to the property of any person arising from the supply network.

[5] Clause 3.1 of the Victorian Electricity Distribution Code requires us to manage our assets in accordance with the principles of good asset management. Under this provision, we must, among other things, develop and implement plans for the management of our assets to minimise the risks associated with the failure or reduced performance of assets. Under clause 5.2, we are required to use best endeavours to meet customers' reasonable expectations of supply reliability.

These factors are combined to produce a health index for each asset in a range from 0 to 10, where 0 is a new asset and 10 represents end of life. The health index provides a means of comparing similar assets in terms of their probability of failure.

We closely monitor assets with a health index in the range 5 to 7 to determine options for intervention, including replacement or retirement, in the context of energy at risk. Interventions are evaluated and planned when asset health index exceeds 5.5 and intervention is prioritised when asset health index exceeds 7.

A health index profile gives an immediate appreciation of the condition of all assets in a group and an understanding of the future condition of the assets.

As part of the CBRM process, the consequence of failure of the asset is also calculated. The consequence of failure consists of four elements:

- network performance
- safety
- financial
- environment.

The risk is calculated by combining the probability of failure of the asset and the consequence of failure of the asset. CBRM is used to calculate how the risk is likely to change in future years. In this way, the CBRM analysis provides:

- a preliminary indication of the likely optimum replacement time of an asset
- a foundation or starting point for further detailed economic assessment to determine the optimum timing of intervention action.

As already noted, the assets at zone substation RP are aged and in poor condition. The economic assessment set out in section 4 provides a detailed analysis of the options to address the identified need.

3.3 22 kV transmission cables

The 22 kV cables supplying zone substation RP from RTS are a steel belted paper lead type construction and date back to the early 1950s and consequently are over 65 years old.

The RTS-RP123 22 kV HV underground cable failed in November 2014 in a location behind the Mary Street Cable Station and the sound wall to the Monash freeway. This cable is direct buried under the sound wall and in practical terms cannot be accessed for repair. This cable was supplying transformer number three at RP zone substation and it is not feasible to return the cable to service.

RTS-RP125 22 kV HV underground cable supplying transformer number two had previously failed in a similar location to the failure on RTS-RP123 22 kV HV underground cable. To maintain the supply at the time of the failure the section of failed cable was bypassed by transitioning the RTS 152 cable to the RTS 125 breaker at RTS and then cutting the 125 and 152 cables due to access difficulty for repairs.

The network has a similar age and type of cable in other parts of the 22 kV system that have experienced failures in the past. Failures are typically occurring in cable sections rather than joints which indicates the cables have reached end of life. For example, the same type of 22 kV cables supplying Sub C experienced 4 failures from 2007 to 2014.

Cable failures are typically benign and do not give rise to safety concerns directly however the time to locate the fault and repair can be take many days. If the failure location is in a highly frequented location or in a major road then repair times are longer and significant disruption can occur while civil works are conducted to uncover the cable, repair and reinstate. Some locations are inaccessible and would require major work to bypass the location with new cable.

3.4 Transformers

The CBRM analysis has determined that the two in-service transformers will have a health index of 6.86 and 6.79 in 2020 and increasing to 8.22 and 8.13 in 2027. These results indicate an end of life state and options to mitigate the risk of failure require evaluation. These transformers were manufactured in 1951 and are over 65 years old.

RP is a three-transformer substation in design. Transformer number three has been out of service since its associated 22 kV sub transmission cable failed in 2014.

The condition issues contributing to the deteriorating health, and associated management risks are summarised as follows:

- In current condition, all three transformers are indicative of increased insulating oil acidity that accelerates insulation paper degradation and already degraded the oil properties. There is evidence of internal corrosion due to the presence of rust and sludge in oil samples taken from coolers. This situation could potentially lead to an internal arcing event should conductive particles be deposited in a location that creates a pathway between live and ground components.
- Oil reconditioning or replacement is currently being risk assessed for potential to temporarily reduce failure risk. There is concern that the process will introduce additional risks, for example conductive particles being deposited between live parts and insulation or tank wall puncture through displacing internal corrosion. The cost of a major off-site refurbishment would not be economically efficient for a transformer of this age and condition. Estimated insulation paper degradation from oil tests is not indicating immediate concern however this is inconsistent with other indicators. Confirmation through paper sampling is not easily achieved as accessing paper insulation is practically difficult due to nature of transformer construction.
- Spare parts are not available for the tap changers and a failure of the tap changer would potentially result in a long outage while parts were re-engineered.

3.5 HV switchgear

The Reyrolle C6T switchgear was manufactured in 1961 and has a health index of 7.0 and rising to 8.0 in 2024. These results indicate an end of life state and options to mitigate the risk of failure require evaluation.

Considerations that are relevant to the timing of retirement or replacement of the Reyrolle circuit breakers include:

- due to the age, slow operation of the circuit breakers during fault clearance may result in damage to the network and potential outage to customers.
- spare parts are no longer available for aged major plant components. Any failure of a critical component will require re-engineering of the part and will delay supply restoration.
- The 6.6 kV switch board is installed with compound filled bus and cable box arrangements. Consequently, it is difficult and time consuming for maintenance and testing activities. In event of

damage involving the bus or cable boxes the requirement to remove, clean-up and replace the compound will result in extended repair times.

- CitiPower's asset strategy is to reduce the high population of oil filled ageing circuit breakers, and transition to vacuum or SF6 type switchgear to improve the personnel safety and reliability of the network. The new generation vacuum or SF6 circuit breakers are cost effective due to reduced lifecycle maintenance and they are more reliable for an increased number of operations.
- the HV switchboard is not arc fault contained or vented, therefore an arc failure of the switchboard or any circuit breaker will pose a safety risk to personnel and other assets in the substation.
- any catastrophic failure of a bus tie circuit breaker may result in two bus section outages disrupting supplies to all customers supplied from RP.

3.6 Building Structure

The inner support walls of the substation have been inspected and show signs of corrosion and water ingress. A report on the building durability indicates that remediation work is required. A decision to utilise the site long term as an operational substation would require additional works to match the building life to the expected life of new electrical assets which is greater than 50 years.

The work required cannot be undertaken while the site is live and this represents a major operational impediment as access to the building would be required while remediation works take place.

3.7 Auxiliary equipment

The site has a large number of aged electro -mechanical protection relays and secondary equipment that was installed when the substation was constructed in the early 1950s or replaced in later years. This equipment is both limited in functionally and creates issues when required to interface with modern relays in future projects.

The RP9 6.6 kV feeder circuit breaker is currently isolated and unavailable for service due to the removal of faulty protection equipment. A like for like replacement of faulty relays is impractical due to unavailability of parts. Where protection equipment failures occur, it is necessary to install new relays and this also requires modification of existing systems to interface with new relays.

The RP protection relays were originally installed on asbestos boards that require removal to ultimately remove this hazard from the site. Isolation of protection systems and new installation according to current safety standards will be expensive and would require a substation outage.

Generally, the other ancillary equipment on site is not built to current standards with safety hazards present and issues with reliability, maintainability and limitations on function.

4 Description of options

This section describes the options, network and non-network, we considered to address the identified need.

4.1 Network options

Table 4.1 provides a description of the credible network options that address the identified need. These options are compared to a 'business as usual' (**BAU**) option, where the existing assets at zone substation RP remain in service and maintenance is undertaken consistent with the condition and age of the assets. Minor capital works will also occur as is essential to keep the substation operational on a 'like for like' basis. That is the BAU option is the case where the asset is not retired or de-rated, but remains in-service, operated, and maintained on a BAU basis.

Table 4.1 Network options ($M, $2019)

Network option description		OPEX Cost	CAPEX Cost
BAU	**Business as usual option** The scope of work includes: • ongoing routine maintenance • essential building remediation works • incidental work to replace end of life minor components	$0.05	$1.0
1	**Convert RP to 11 kV and continue to provide 6.6 kV distribution** The scope of work includes: • remove the existing transformers and install a three 11/6.6 kV (7.5 MVA) step down transformers at RP • remove the 6.6 kV switchboard and install new 6.6 kV switchboards and circuit breakers • install three dedicated 11 kV feeders directly from WP zone substation into the new auto transformers • replace all secondary systems and auxiliary equipment • decommission the 22 kV transmission feeders • building remediation works to match expected new equipment life (>50 years) This option eliminates the need for capital expenditure to upgrade 6.6 kV distribution substations to 11 kV. However, the islanded 6.6 kV network would be retained indefinitely and limits operational flexibility, backup capability and ability to meet future demand growth.	$0.025	$15.4

Network option description		OPEX Cost	CAPEX Cost
2	**Retire RP and offload to WP, remove all equipment** The scope of work includes: • decommission RP and remove all equipment • install four dedicated 11 kV feeders from WP zone substation • upgrade 6.6 kV distribution substations and switchgear to 11 kV • decommission the 22 kV transmission feeders • building remediation works necessary for a decommissioned site This project aligns with our strategy to retire the 22 kV sub transmission network and upgrading the associated 6.6 kV distribution network to the current operational standard of 11 kV.	$0.005	$12.6
3	**Like for like rebuild of RP substation and 22 kV transmission cables** The scope of work includes: • remove the existing transformers, circuit breakers and all secondary and ancillary equipment • install three 22/6.6 kV (10 MVA) transformers • install three section 6.6 kV switchboard • replace all secondary and ancillary equipment • repair and reinstate third 22 kV sub transmission cable from RTS • building structural and remediation works to match expected new equipment life (>50 years) This option eliminates the need for capital expenditure to upgrade 6.6 kV substations to 11 kV. However, the islanded 6.6 kV network would be retained indefinitely and limits operational flexibility, backup capability and ability to meet future demand growth.	$0.025	$19.5

The new WP zone substation is currently under construction and is scheduled to be commissioned in 2020. This substation has sufficient capacity to supply the RP load in the long term and spare circuit breakers are available for the 11 kV cables required for Option 1 and Option 2.

Option 2 includes costs to upgrade the 6.6 kV distribution network to 11 kV however this allows other costs to be avoided. Conversion to 11 kV also provides significant operational benefit over options to retain the 6.6 kV network. The RP load and the adjacent 11 kV load will have greater interconnectivity with this option. Consequently, security of supply will be improved and it will also allow lower cost options to meet load growth in the future.

Several other network options were also considered, but they were rejected as being infeasible. Details are provided in section 4.3 below.

4.2 Non-network options

Due to its location within the Melbourne CBD and the nature of the customers that zone substation RP supplies, CitiPower has determined that there are no credible non-network options that could address the energy at risk to defer or replace the proposed works. This determination is made under clause 5.17.4(c) and (d) of the NER.

In summary, our reasons for this conclusion are:

- there is no opportunity to reduce the required assets and associated works at RP zone substation by partially reducing peak load through demand management
- due to its location within the Melbourne CBD, an embedded generation option would not be feasible or a cost-effective long-term solution

This determination was published in accordance with clause 5.17.4(d) 07/10/2019 and no responses were received regarding this determination. In accordance with these provisions, CitiPower will not publish a non-network options report in relation to the proposed network need at RP zone substation and will proceed with the draft project assessment.

4.3 Other network options considered but rejected

Consideration was also given to options to supply the RP load at 11 kV from the two other nearby substations, MP and FR. These options were rejected as both these substations have insufficient capacity to meet the load supplied from RP. To meet the requirements under the CBD Security of Supply Upgrade Plan [6] load has been transferred away from both these substations and introducing new load would trigger substantial works to comply with mandatory CBD load security requirements. An additional factor is that spare circuit breakers are unavailable at both these substations with no practical way to provide the dedicated circuit breakers required.

A variation of Option 2 considered was to leave decommissioned equipment in place at RP after the load was transferred to WP to avoid removal and disposal costs of existing equipment. This option was rejected as poor industry practice to leave an environmental and safety liability in place, albeit diminished with a mostly unenergised site. Removal of the equipment is also prudent to maintain options for future use of the site, access to the site is difficult and this will become a greater restriction and impose greater costs with time.

[6] Essential Services Commission of Victoria, Final Decision: CBD Security of Supply, February 2008

5 Detailed economic assessment

In this section we present the results of our economic assessment of the business as usual and three credible options set out in table 4.1. The purpose of this assessment is to identify the preferred option, which is then subject to sensitivity analysis and analysis to determine optimum timing.

In identifying the preferred option, the objective is to maximise net economic benefit[7]. Each of the credible options would meet the need as identified in Section 3, in terms of continuing to reliably supply load to the customers who are presently supplied from zone substation RP. Therefore, the preferred option can be identified as the one that minimises total present value cost.

5.1 Methodology

The methodology we have applied in this assessment accords with the approach prescribed in the AER documents "Application guidelines - Regulatory investment test for distribution - December 2018" and "Industry practice application note - replacement planning - January 2019".

Under the methodology, the annual risk cost of an asset (or group of assets) is calculated as the probability of asset failure multiplied by the likelihood of consequence of the asset failure multiplied by the consequence cost of the failure event.

To calculate the annual risk cost of the assets at zone substation RP, we have modelled four key failure modes listed in the table below.

Table 5.5.1 Modelled asset failure modes

Failure mode	Description
1	Catastrophic failure of a transformer (irreparable damage to all three transformers)
2	Catastrophic failure of a CB (irreparable damage to a bus section)
3	Disruptive failure of a transformer (irreparable damage to one transformer)
4	Disruptive failure of a CB (irreparable damage to a CB)

The analysis has not modelled all failure modes as additional failure modes are not expected to have material impact on the identification of the preferred option. Furthermore, such endeavour will constitute effort that is not commensurate with the costs of the project. This is a conservative assumption as the full risk costs are expected to exceed those calculated in this analysis.

The consequence costs for each failure mode were estimated in each of the following consequence areas:

- involuntary supply interruption
- safety (i.e. threat to human life)
- operating expenditure (principally for emergency generators)

7 Clause 5.17.1(b) of the Rules.

- capital expenditure associated with the reinstatement or replacement of failed and damaged assets
- capital expenditure associated with installing alternate assets to restore supply
- environmental costs such as oil spillage and site clean-up
- costs associated with disruption to adjacent businesses and residents

Annual asset failure and consequence probabilities were derived from historical asset performance data and used in CBRM modelling.

The probability-weighted cost of each failure mode based on the likelihood that the cost would be incurred was calculated and these were summed to derive an estimate of the total expected annual risk cost. The total present value of the risk cost is calculated and the present value of CAPEX and OPEX costs to implement each of the credible options is also calculated. This provides a basis for comparison between BAU and credible options to determine a preferred option.

In a project where the identified need is for reliability corrective action such as this situation the net economic benefit is typically negative and the preferred option can be identified as the one that minimises total present value costs, avoiding costs associated with an increased probability of failure.

This is defined in NER clause 5.17.1(b) that states that the purpose of the RIT–D is to:

> *...identify the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action.*

5.2 Key variables and assumptions

Table 5.5.2 below lists the key variables and assumptions applied in the economic assessment. The table also sets out the upper and lower bounds of the range of forecasts adopted for each of these variables. We used these ranges to undertake scenario analysis, as explained in section 5.1. Upper and lower bounds have been selected based on reasonableness estimates and with consideration of the sensitivity analysis results presented in section 5.5. This ensures the modelling considers the variability in parameters that have more significant impact on the results.

Table 5.5.2 Variable ranges for sensitivity testing purposes

Variable / assumption	Lower bound	Central estimate	Upper bound
Cost of involuntary supply interruption	30% reduction in central estimate	Value of Customer Reliability (**VCR**) of $44,515 per MWh (weighted average by customer class)	50% increase in central estimate
Safety cost	30% reduction in central estimate	Value of statistical life of $4.4M[8]	50% increase in central estimate
Safety cost disproportionality factor	Central estimate	Factor of 3	Central estimate
Emergency generation cost	20% reduction in central estimate	In-house estimate using high -level scopes	20% increase in central estimate
Network operating expenditure	20% reduction in central estimate	Cost forecast based on asset operating and maintenance requirements	20% increase in central estimate
Network capital expenditure	20% reduction in central estimate	In-house cost estimates using detailed and high-level project scopes	20% increase in central estimate
Environmental costs	20% reduction in central estimate	In-house cost estimates using detailed and high-level project scopes	20% increase in central estimate
Probability of asset failure	30% reduction in central estimate	Historical asset performance data, plus forecasts based on condition monitoring and CBRM modelling	30% increase in central estimate
Discount rate (real pre-tax)	2.75% real, being the pre-tax equivalent of the regulated WACC[9]	30% increase in lower estimate	80% increase in lower estimate

8 Department of the Prime Minister and Cabinet - Office of Best Practice Regulation, Best Practice Regulation Guidance Note: Value of statistical life, December 2014.

9 Paragraphs 16 and 17 of the RIT-D state: "The present value calculations must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. The discount rate used must be consistent with the cash flows that the RIT-D proponent is discounting. The lower boundary should be the regulated cost of capital."

5.3 Scenarios adopted for option assessment

NER clause 5.17.1 requires RIT–D proponents to base the RIT–D assessment on a cost benefit analysis that includes an assessment of reasonable scenarios. We have developed five reasonable scenarios to test the economic assessment with different combinations of plausible variations in the input values.

Material uncertainty and risk regarding assumptions of values for input parameters for economic benefit assessment is accounted for through selection of credible scenarios that reasonably reflect potential future states. A further step is to assign a reasonable probability to each of these reasonable scenarios occurring in practice. Regarding this report we consider the central scenario as the most likely and all other scenarios of lower but equal likelihood. Consequently, a higher probability has been assigned to the central scenario and an equal lower probability to the other 4 scenarios as shown in Table 5.3 below.

Table 5.3 Guide to scenarios

Scenario	Description	Probability of Occurrence
Central scenario	This scenario adopts the central estimate for each variable in the economic assessment. It represents the most likely outcome.	40%
Scenario A	This scenario represents a combination of variables that assess a high risk cost and high failure probability	15%
Scenario B	This scenario represents a combination of variables that assess a low risk cost and low failure probability	15%
Scenario C	This scenario represents a scenario where risk costs and failure probability are central however the lower bound discount rate is modelled	15%
Scenario D	This scenario represents a scenario where risk costs and failure probability are central however the upper bound discount rate is modelled	15%

Table 5.4 below describes the input parameter variations selected to create the scenarios described above.

Table 5.4 Definition of scenario input parameters

Scenario Inputs	Central Scenario	Scenario A	Scenario B	Scenario D	Scenario D
Probability of failure	Central	Upper	Lower	Central	Central
Safety Cost	Central	Upper	Lower	Central	Central
Capital expenditure	Central	Upper	Lower	Central	Central
Operating Expenditure	Central	Upper	Lower	Central	Central
Cost of Unplanned Loss of Supply	Central	Upper	Lower	Central	Central
Temporary Generation Costs	Central	Upper	Lower	Central	Central
Environmental cost	Central	Upper	Lower	Central	Central
Discount rate	Central	Central	Central	Lower	Upper

5.4 Economic Assessment Results

The net present cost and ranking for each scenario for the BAU option and the three credible options is calculated according to the methodology described above and summarised in Table 5.5 below.

Table 5.5 Net economic costs of business as usual and credible options ($M, $2019) under different credible scenarios

Scenario		Option BAU		Option 1		Option 2		Option 3	
		Net Present Cost	Rank	Net Present Cost	Rank	Net Present Cost	Rank	Net Present Cost	Rank
Central	Most likely scenario inputs	$48.95	4	$14.94	2	$11.80	1	$18.80	3
A	High cost and high failure probability	$91.48	4	$17.93	2	$14.15	1	$22.55	3
B	Low cost and low failure probability	$25.02	4	$11.95	2	$9.44	1	$15.04	3
C	Low discount rate	$55.12	4	$15.21	2	$12.04	1	$19.13	3
D	High discount rate	$43.71	4	$14.68	2	$11.56	1	$18.48	3
All	Probability Weighted	$51.88	4	$14.94	2	$11.80	1	$18.80	3

The analysis indicates Option 2 is ranked as the preferred option for the overall probability weighted scenario.

The ranking of Option 2 as the preferred option is unaffected by plausible variations from the central estimates of economic modelling input parameters. Under each combination of input parameters and the weighted probability scenario, Option 2 is the least-cost (or most efficient) option.

Significant risk costs are associated with the BAU option due to the increasing failure rates of aged assets, high customer and safety impacts and significant load at risk with limited means of quickly restoring all supply should a failure occur.

Several conservative assumptions have been taken in the analysis that have reduced the risk cost of the BAU option. Had all possible risk costs been included the analysis result would have been even more conclusive for Option 2. Consequently, it was deemed that there was no value in modelling additional failure modes given this would not have impacted on the RIT-D objective of selecting the most beneficial option.

In particular the following conservative assumptions have been made. Allowance has been made in the BAU option to utilise temporary generators to reduce outage durations for customers and significantly reduce the risk cost of unserved energy. In a practical sense the use of generators will be very difficult due to the poor access to distributions substations for connection, limited suitable locations, the setup time required, the approvals required and community acceptance regarding noise. It was however assumed in the analysis that it would be possible, and this is a conservative assumption. If generation is not possible then the risk costs for the BAU option would be significantly higher. The location of a residential building above the substation is another risk factor and a catastrophic impact on that building has not been included and this is a conservative assumption. A significant impact on this building is a very low probability but potentially high impact event. Also as noted above, for simplicity only four failure modes have been modelled which is a conservative assumption as modelling all failure modes would further increase the risk cost.

The ranking of Option 2 as preferred is not unexpected given that, while each of the network options would avoid the risk costs associated with the BAU option, Option 2 achieves this at the lowest cost.

It important to note that Option 2 also provides significant benefits not quantified in the analysis by removing a significant amount of legacy 6.6 kV network from the CBD. These benefits include:

- Network operational flexibility and security with greater opportunity to switch load around the 11 kV network in response to faults or network access requirement in the area supplied by RP and adjacent areas.
- Increased options to supply future load growth at lower cost
- Reduced requirement to hold specialised spares for the 6.6 kV network

5.5 Sensitivity Analysis

A sensitivity analysis has been undertaken to determine the proportionate variability in the economic cost calculation given a variation in individual input parameters.

This analysis provided a focus for efforts to accurately forecast input valves used in the analysis. Additional review has occurred for variables that provide the greatest contribution to changes in the economic cost result. The analysis also informs the selection of upper and lower bounds that form the basis of scenarios used for assessing each option and the BAU option.

Table 5.6 below demonstrates the variability in the economic cost in percentage terms given a 20 percent variation in the input parameter with all other inputs remaining unchanged.

Table 5.6 Model Input Sensitivity

	BAU Option		Preferred Option (Option 2)	
Input Parameter	**% change in net economic benefit for 20% reduction in input value**	**% change in net economic benefit for 20% increase in input value**	**% change in net economic benefit for 20% reduction in input value**	**% change in net economic benefit for 20% increase in input value**
Probability of failure	-19.4%	19.4%	0.0%	0.0%
Safety Cost	-10.0%	10.0%	0.0%	0.0%
Capital expenditure	-2.3%	2.3%	-19.3%	19.3%
Operating Expenditure	-0.3%	0.3%	-0.7%	0.7%
Cost of Unplanned Loss of Supply	-6.0%	6.0%	0.0%	0.0%
Temporary Generation Costs	-0.3%	0.3%	0.0%	0.0%
Environmental cost	-0.7%	0.7%	0.0%	0.0%
Discount rate	-6.3%	5.8%	-0.9%	0.9%

This analysis highlights that the risk cost associated with the BAU option is most influenced by the assumptions associated with the probability of failure. The probability of failure assumptions have been derived from detailed CBRM modelling and we have confidence that this methodology provides robust values that are suitable and appropriately accurate for the economic benefit analysis. To provide further reassurance, given the uncertainty in forecasting failure rates, scenarios were selected that test the upper and lower bounds of probability values and the preferred option is unchanged.

The economic cost calculated for Option 2 is most sensitive to a variation in the forecast capital expenditure to deliver this option. This is not unexpected as risk costs associated with Option 2 have been assessed as negligible given that new assets will be installed with very low failure rates for the period of the analysis and the capital project cost is the key cost driver.

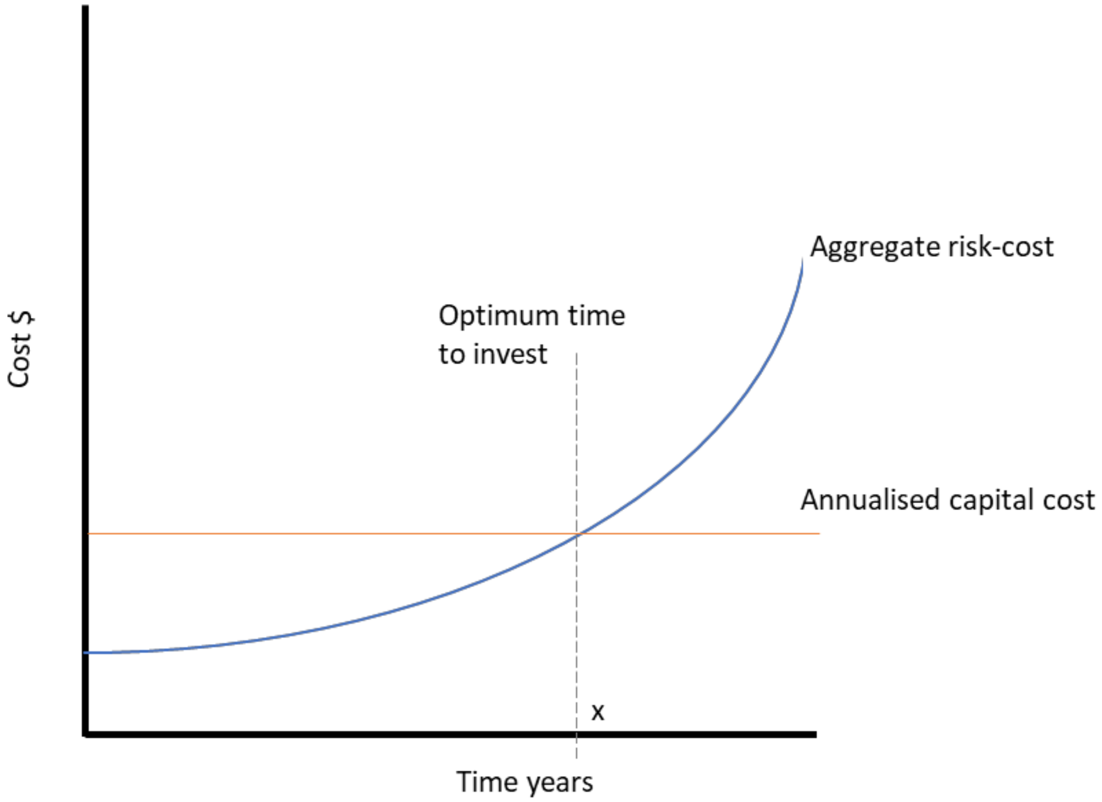
The results of the sensitivity analysis have been considered in framing upper and lower bounds and creating scenarios. Consequently, we are satisfied the methodology is robust and the results of the economic assessment are suitable to determine the preferred option to minimise costs.

5.6 Optimum Timing Analysis

Generally, the optimum timing of a credible option for a replacement RIT–D project would be when the present value of the aggregate risk cost for the BAU option exceeds the present the value of the replacement project cost. That is the economically prudent and efficient timing for asset retirement is indicated by time that the annual benefit from the proposed option exceeds its annualised cost, in this case the benefit is to avoid the higher costs of failure.

This is shown graphically in Figure 5.1 below[10].

Figure 5.1 Optimum Investment Timing



Analysis has been undertaken to calculate the optimum timing for the preferred option for each of the scenarios modelled as defined in Table 5.4 above. The present value of the preferred option project cost is plotted against the annual risk costs of the BAU option for each scenario in Figure 5.2 to Figure 5.6 below.

[10] Page 79 AER Industry practice application note - replacement planning - January 2019

Figure 5.2 Results of optimum timing economic assessment—Central Scenario

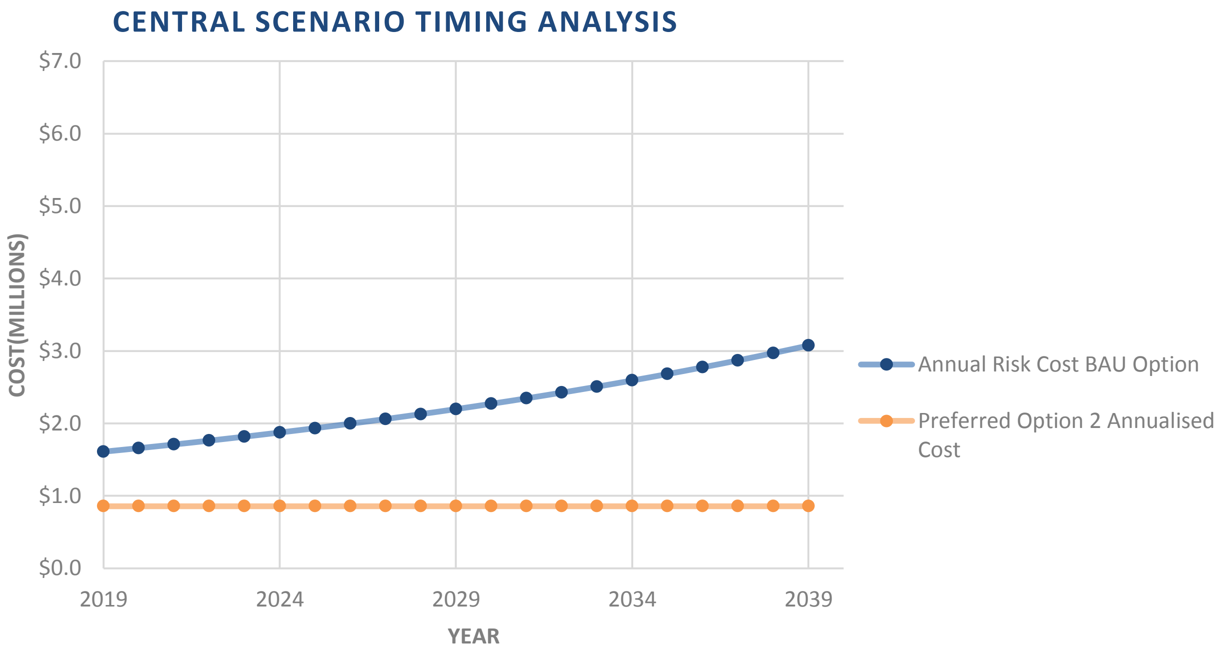


Figure 5.3 Results of optimum timing economic assessment—Scenario A

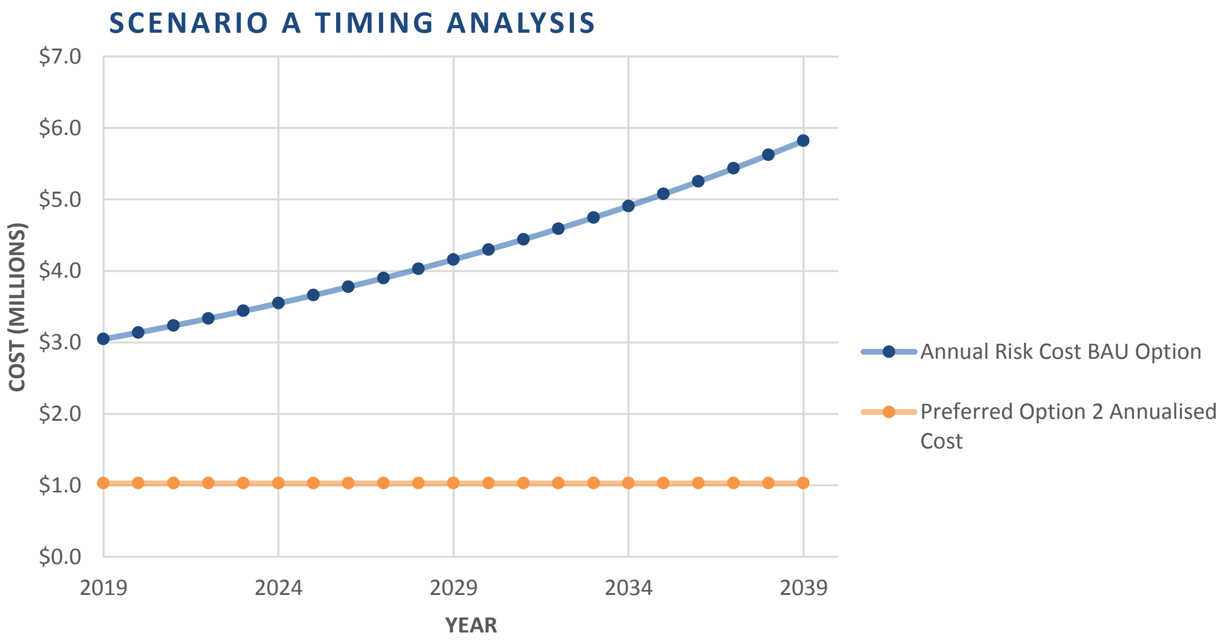


Figure 5.4 Results of optimum timing economic assessment— Scenario B

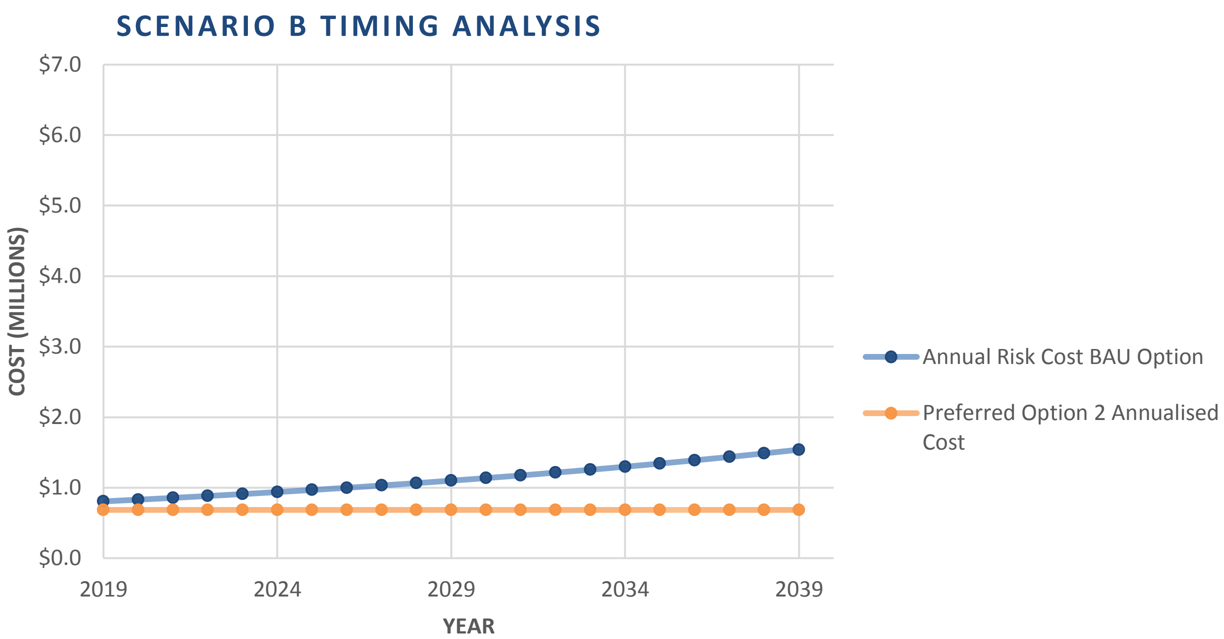


Figure 5.5 Results of optimum timing economic assessment— Scenario C

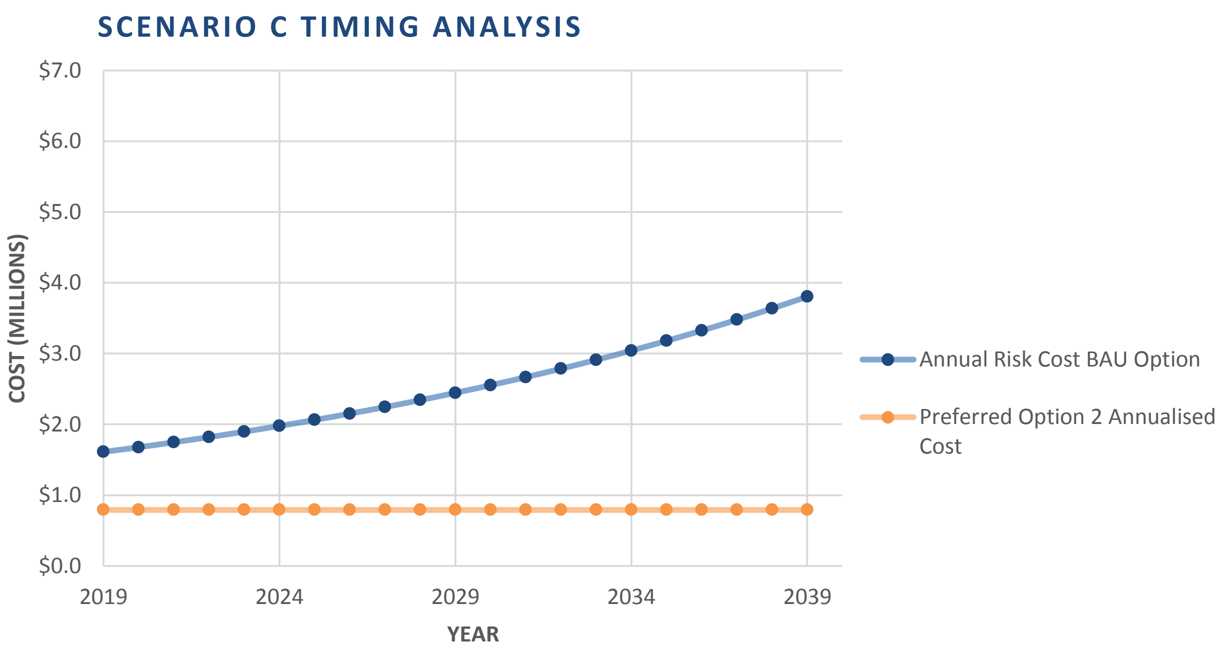
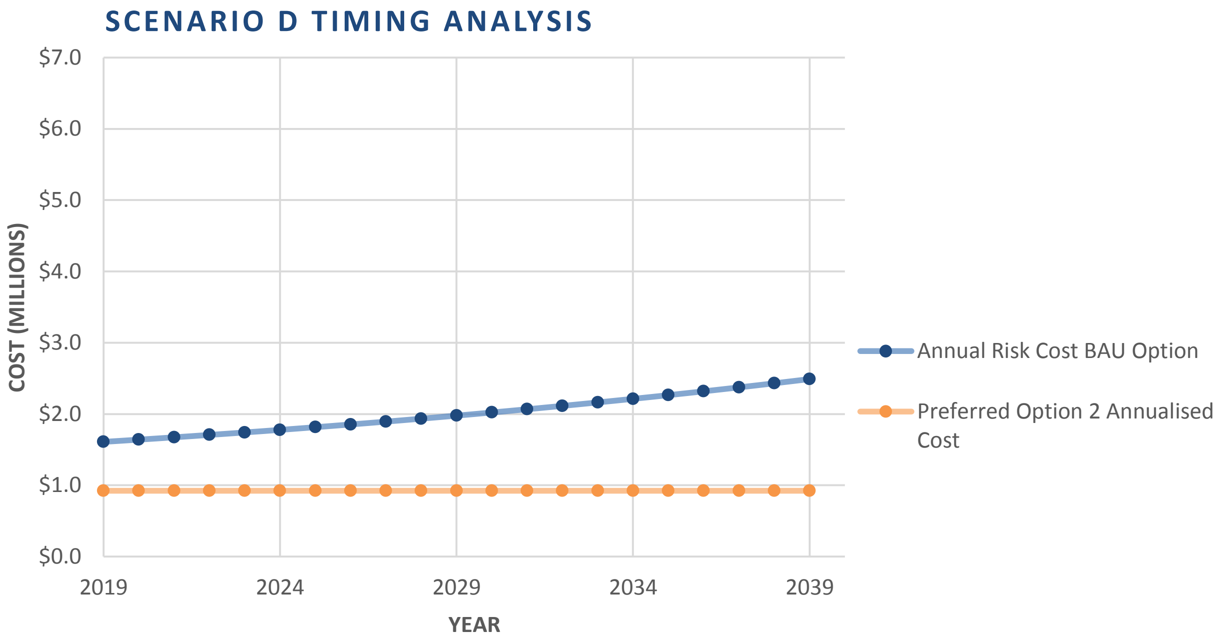


Figure 5.6 Results of optimum timing economic assessment— Scenario D



The annualised risk cost of the BAU option remains above the annualised cost of Option 2 from the current date and into the future for all scenarios. This indicates that the optimum time for the replacement project under all scenarios is prior to the current date and the proposed preferred option should be completed as soon as practical.

As noted earlier in this report the situation regarding asset condition at RP has been under review for several years. The design and construction of WP has been undertaken with consideration of providing an option to supply the load currently supplied by RP. It was determined prudent to delay taking earlier action until WP was available as this was expected to provide the most economically prudent and efficient solution. WP is currently in the final stages of construction and is expected to be commissioned into service in 2020.

5.7 Satisfaction of RIT-D

The proposed preferred option, Option 2, satisfies the RIT-D. This statement is made based on the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

6 Lodging a submission

We invite written submissions on the preferred solution identified in this report from any interested parties. Our aim is to develop the distribution network in a manner that maximises net economic benefits to all those who produce, consume and transport electricity in the NEM. We welcome submissions that may assist in this regard.

Submissions can be provided electronically to the email address provided below:

ritdenquiries@citipower.com.au

Alternatively, submissions may be lodged by mail to the following address:

Andrew Dinning

Generation and Major Augmentation Manager

CitiPower Australia Limited, Locked Bag 14090 Melbourne Vic 8001.

All submissions will be published on our website. If you do not want your submission to be published, please state this at the time of lodgement.

All submissions are due on or before 17:00 on 17 January 2020.

Following our review of any submissions made, the option chosen to address the identified need will be set out in the final project assessment report. That report will represent the final stage of the RIT-D assessment process.

We intend to complete our review of submissions and the selection of the final project assessment report by 31 January 2020.

7 Checklist of regulatory compliance

Table 7.1 lists the sections of this report that contain the information required by clause 5.17.4(j) of the Rules.

Table 7.1 Regulatory compliance checklist

Rules clause	Requirement	Section of this report
5.17.4(j)(1)	Description of the identified need for the investment	Section 3
5.17.4(j)(2)	The assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, reasons that the RIT-D proponent considers reliability corrective action is necessary)	Section 3
5.17.4(j)(3)	If applicable, a summary of, and commentary on, the submissions on the non-network options report	Section 4.2
5.17.4(j)(4)	Description of each credible option assessed	Section 4
5.17.4(j)(5)	Where a Distribution Network Service Provider has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit for each credible option	Sections 5.1 and 5.2
5.17.4(j)(6)	A quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	Table 4.1
5.17.4(j)(7)	A detailed description of the methodologies used in quantifying each class of cost and market benefit	Sections 5.1 and 5.2
5.17.4(j)(8)	Where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option	Not applicable
5.17.4(j)(9)	The results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results	Section 5.4
5.17.4(j)(10)	The identification of the proposed preferred option	Section 5.4
5.17.4(j)(11)	For the proposed preferred option, the RIT-D proponent must provide: • details of the technical characteristics • the estimated construction timetable and commissioning date (where relevant) • the indicative capital and operating cost (where relevant) • a statement and accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for distribution • if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	Table 4.1 Not applicable Table 4.1 Section 5.7 Not applicable
5.17.4(j)(12)	Contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed	Section 6