CITIPOWER

Collingwood supply area

CP BUS 4.05 - B supply area - Jan2020 - Public

Regulatory proposal 2021–2026

CitiPower

Sep 2019

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1 Overview

Business	CitiPower
Title	Collingwood supply area
Project ID	CP BUS 4.05 - B supply area - Jan2020 - Public
Category	Replacement
Identified need	The identified need is to address the increasing risks to safety and reliability of supply associated with the deterioration of the assets at Collingwood zone substation
Recommended option	Replace existing switchboard in the same building
Proposed start date	2020/21
Proposed commission date	2023/24
Supporting documents	CP MOD 4.02 - B supply area - Jan2020 – Public CP ATT105 - Ausgrid - Project justification for 11kV switchgear - Jan2019 – Public CP ATT107 - PowerWater - Berrimah substation condition - Feb2018 – Public CP ATT112 - Western Power - Network management plan - Sep2011 - Public CP ATT225 - TasNet - Investment evaluation summary - Nov2018 - Public

Source: CitiPower

This business case outlines the credible options to maintain the safety and security of supply for customers served by our Collingwood (**B**) zone substation.

B zone substation was constructed in the early 1960s and most of the original substation equipment remains in service. This includes the existing Email Westinghouse LC air-insulated single bus switchboard and bulk oil-filled switchgear which was designed with no arc fault containment.

Following an assessment of a range of options, including the risk associated with each option, we found that replacing the existing switchboard will meet the identified need at the least life-cycle costs.

The forecast capital expenditure requirements for the 2021–2026 regulatory period, for the preferred option, are outlined in table 1. These forecasts have been developed in calendar year terms and converted to financial years in our consolidated expenditure modelling following changes to our reporting period (as required by the Victorian Government and the Australian Energy Regulator).

Table 1 Expenditure forecasts for preferred option ($ million, 2019)

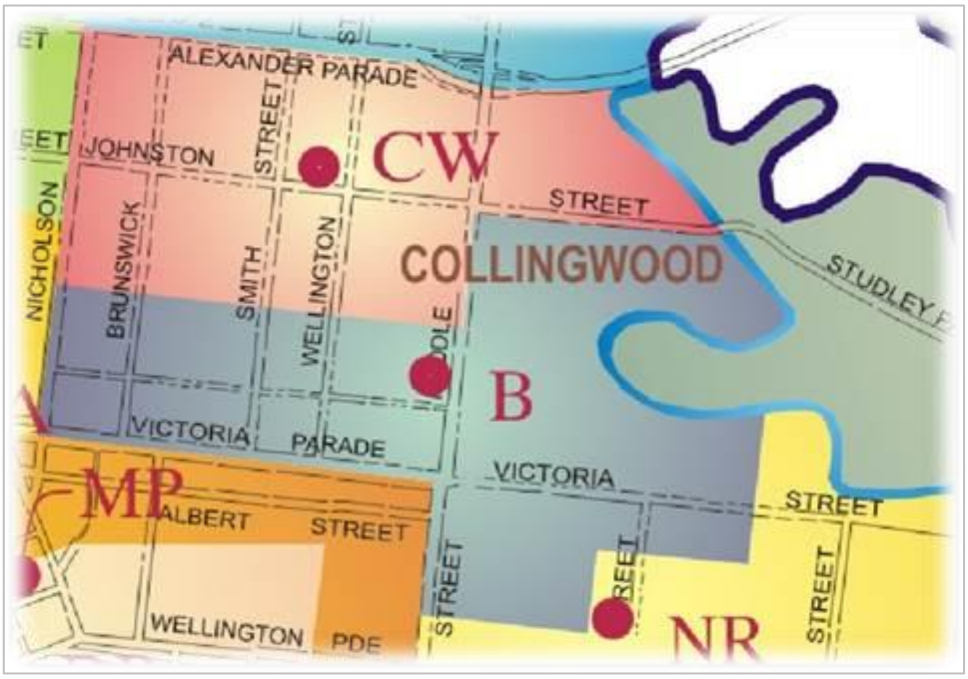
Expenditure forecast	2021/22	2022/23	2023/24	202/254	2025/26	Total
Total capital expenditure	1.19	4.21	3.06	-	-	8.45

Source: CitiPower

2 Background

Our B zone substation is located at 178 Langridge Street, at the junction of Islington Street and Hoddle Street in Collingwood (as shown in figure 1). It provides electricity supply to over 6,300 commercial, industrial and domestic customers. Approximately 75% of these customers are residential, and major customers include Yarra Trams, St Vincent's Hospital and Carlton United Breweries.

Figure 1 B zone substation supply area



Source: CitiPower

2.1 Zone substation characteristics

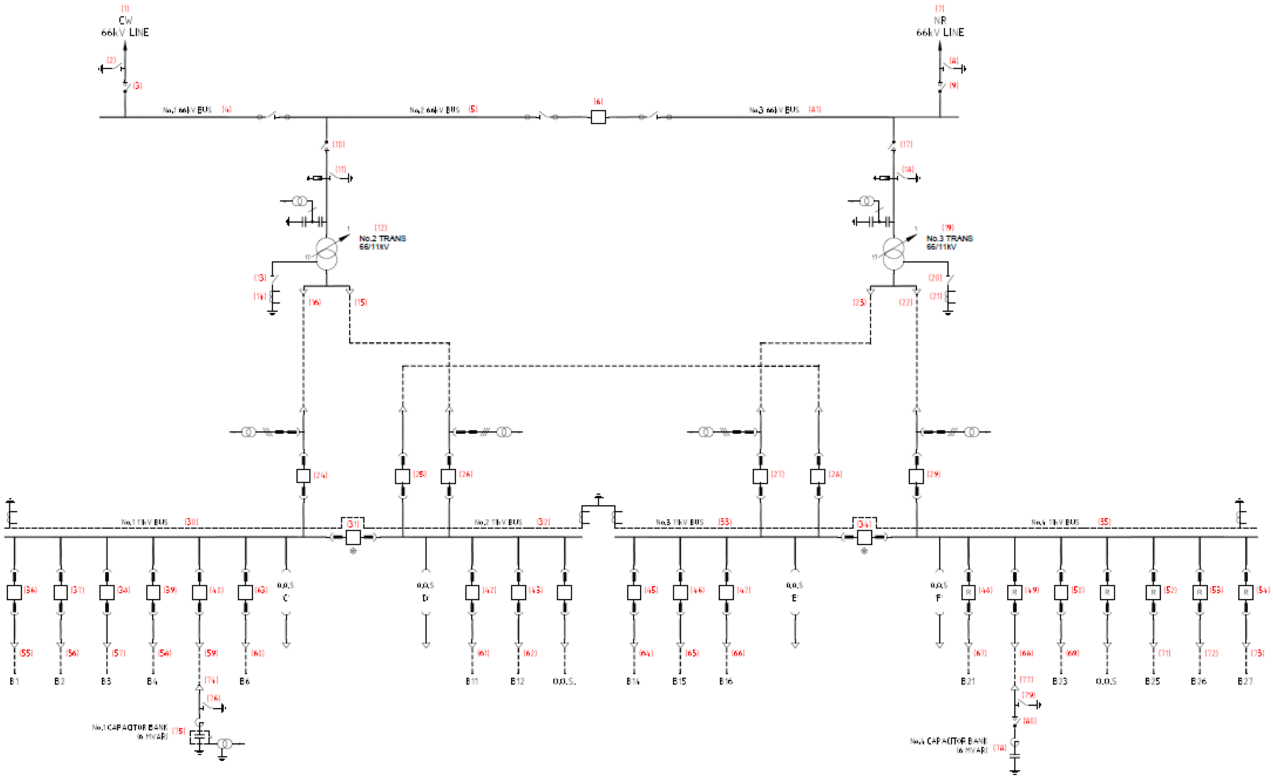
B zone substation contains a 53-year-old switchboard consisting of Email LC 11kV switchgear with 25 J18 oil-filled circuit breakers in service. These types of LC switchboards are not designed to contain internal arc-faults.

The zone substation configuration includes a four-section single busbar arrangement and two switched capacitor banks that are required for voltage management. The switchgear has air-insulated busbar chambers with compound-filled cable boxes, and oil as the insulation and arc interrupting medium in the circuit breakers.

The zone substation is served by two sub-transmission lines operating at 66kV; one from Collingwood (**CW**) and the other North Richmond (**NR**). A 66KV bus tie circuit breaker provides interconnection between CW and NR in conjunction with isolators.

An electrical schematic of the existing layout is shown in figure 2.

Figure 2 B zone substation: single line diagram



Source: CitiPower

3 Identified need

The identified need is to maintain a safe and reliable supply of electricity to customers in the B supply area, recognising the risks associated with the existing switchboard, including:

- the increased risk of failure posed by the weakening of the integrity of the switchboard as a result of damage sustained in 2016
- site-specific factors exacerbating potential adverse consequences of failure
- the higher consequence of non-arc fault contained assets, as recognised by the shift away from these asset types by the broader energy industry.

These factors are discussed in further detail below, and a monetisation of these risks and consequences is provided in section 5.

3.1 Risk of failure from the switchboard at our B zone substation

The risk of failure associated with the switchboard at our B zone substation is driven by previous asset failures and the ongoing deterioration as the switchboard ages.

3.1.1 Asset failure history

In 2016, the switchboard at our B zone substation suffered significant damage as a result of disruptive failure of the B23 feeder circuit breaker. This affected the energy supplied to 1,200 customers and posed a significant safety risk to employees, with the resulting rise in pressure and subsequent explosion blowing open the doors in the switch room.

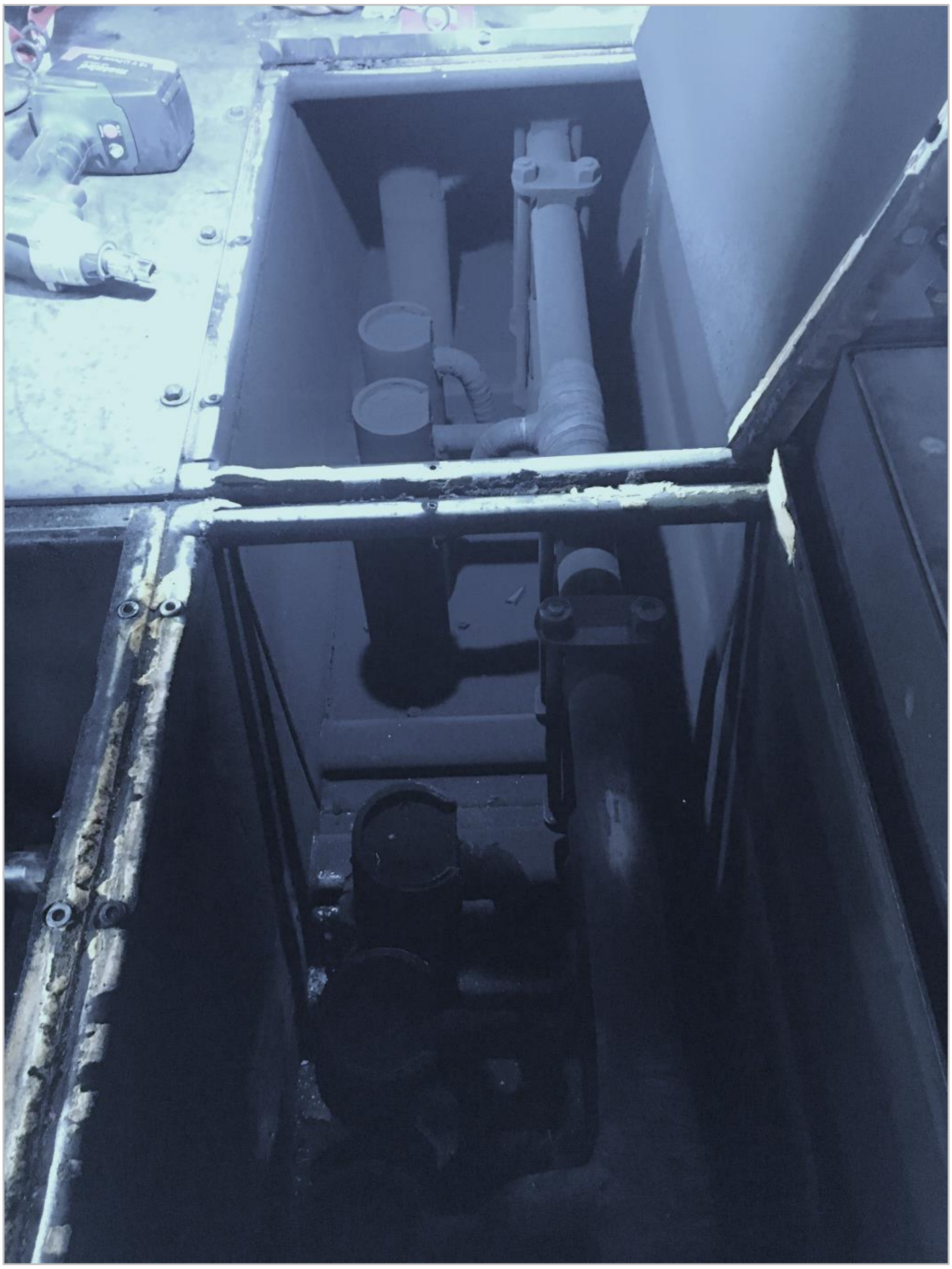
The metal cladding on the switchboard suffered extensive damage, requiring two circuit breakers (B23 and B24) to be decommissioned and their loads transferred to spare feeder positions. Extensive clean up and repairs were also required to the no.4 bus and the switch room due to fire and heat damage.

The damage to the B23 switchboard and busbar chamber is shown below.

Figure 3 Damage to B switchboard and switch room following circuit breaker failure

Source: CitiPower

Figure 4 Damage to B no.4 busbar following circuit breaker failure



Source: CitiPower

Figure 5 Damage to rear of air-insulated busbar chamber and switch room due to uncontained arc fault

Source: CitiPower

Figure 6 Damage and distortion of busbar chamber adjacent to failed circuit breaker busbar spouts

Source: CitiPower

At the time of the incident we repaired, rather than replaced, the switchboard to address the resulting reduction in system security. This switchboard type is obsolete, so repairs were carried out using reclaimed parts from another decommissioned switchboard. The switchboard was repaired to a lesser capacity than before the fault occurred.

This repair was never intended to be a long-term solution due to the increased risk of failure posed by the weakening of the integrity of the switchboard as a result of the sustained damage.

3.1.2 Potential risk of arcing detected through condition monitoring

Following the circuit breaker failure in 2016, online monitoring equipment was installed on the no.4 bus to provide assurance of the integrity of the repaired insulation. This system provides constant monitoring of partial discharge (**PD**) activity on the switchboard.[1]

Heat generated from arcing can damage the dielectric properties of the insulation in the chamber and adjacent chambers, making it less effective. This leads to a higher risk of partial discharge activity which over time can cause subsequent arc faults and result in loss of supply to customers as well as endanger the safety of staff.

1 EA Technology's UltraTEV Monitor system utilises two types of sensing technology to find and locate sources of discharge. TEV sensors will detect hidden discharge sources caused by voids and defects within the putty and tape insulation. Airborne ultrasonic sensors will detect surface discharge activity occurring across the surface of insulation. This system provides an opportunity to detect changes in partial discharge activity levels and provide early warning of impending failure. As a control measure, its intent is to allow pre-emptive actions to be taken should the insulation start to fail thus avoiding another disruptive failure at the B zone substation, especially whilst people are on site.

Our tests indicate that there are low levels of partial discharge activity on the no.4 bus. These early indications of potential arcing are factored into the probability of failure of the switchboard at our B zone substation.

PD monitoring has not been installed on the other three buses, meaning we are unable to monitor potential arcing in these areas in real-time.

3.2 Consequences of failure from the switchboard at our B zone substation

The potential consequences of a switchboard failure at our B zone substation are largely driven by the likely reliability and safety impacts. These impacts reflect the characteristics of the switchboard and the zone substation design.

For example, the consequence of partial discharge in the busbar area of the switchboard is particularly high, as an arc-flash can result in the loss of a complete busbar section or the whole switchboard.

The layout of our B zone substation is also such that the switchgear is situated directly opposite the protection and control equipment, with no form of blast control wall between them or between the bus-sections. The failure of an oil-filled circuit breaker can result in the expulsion and ignition of the insulating oil. As there is no arc fault containment within the switchgear panels, any burning oil expelled from the switchgear could be spread into the open switch room, with the potential to cause damage to the other equipment within the room. Consequently, the failure of one of these circuit breakers could result in the loss of all the switchgear protection and control equipment at this zone substation.

3.3 Industry shift away from non-arc fault contained switchboards

Broader industry experience supports the view that compound-filled and non-arc fault contained switchboards pose an increasing safety and reliability risk. For example:

- Ausgrid's regulatory proposal and revised regulatory proposal for its 2019–2024 regulatory period indicates their intention to replace compound-filled switchboards as a commitment to implementing current industry best practice[2]
- Western Power experienced four catastrophic failures of compound-filled switchboards in the 10-year period to 2010[3]
- TasNetworks have proposed to continue their program, initiated in 2014, to replace non-arc rated HV metal-clad switchgear installed on their transmission network due to safety and operational risks associated with these assets[4]
- Power and Water Corporation are replacing their non-arc contained switchboards due to safety concerns following an incident at their Berrimah substation in 2017, in which an operator suffered second degree burns.[5]

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2 CP ATT105: Ausgrid, *Revised Proposal, Attachment 5.14.1 Project Justification for 11kV Switchgear*, January 2019.

3 CP ATT112: Western Power, *Appendix L – Network Management Plan*, September 2011, p. 7–55.

4 CP ATT225: TasNetworks, *Investment Evaluation Summary*, November 2018

5 CP ATT107: PowerWater, *Berrimah Zone Substation Condition Assessment Report*, February 2018.

4 Options analysis

We considered several options to address the risks posed by the switchboard at our B zone substation. These alternatives are shown in table 2.

Table 2 Summary of option costs ($million, 2021)

	Option	Costs
1	Maintain status quo	-
2	Offload B zone substation to NR	14.6
3	Replace existing switchboard in the same building	8.5
4	Non-network solutions	N/A

Source: CitiPower

The two network options we assessed are expected to equally reduce the risk at the zone substation. As such, our preferred option—option three, replace the existing switchboard—is that with the lowest cost.

The efficient timing of our preferred option is determined relative to the maintain status-quo option, based on our risk monetisation approach (set out in section 5).

For the reasons outlined below, we do not expect a non-network solution to be economic.

4.1 Option one: maintain status quo

Option one involves managing the risk posed by the existing switchboard at our B zone substation without major intervention. This option is expected to result in a deterioration of reliability performance, as the increasing risk of catastrophic failure results in interruptions to customer supply for extended periods of time. These risk costs have been monetised in our attached model, and as noted previously, are compared to the preferred option to determine the efficient timing of any intervention.

In assessing the potential risk costs, we have used the cost of replacement on a planned basis. This provides a conservative assessment of the potential risk-cost of maintaining the status-quo, as the costs of responding to a catastrophic failure are greater than those for a planned intervention.

The testing or maintenance work associated with the protection and control equipment can only be undertaken while the switchboard is live. This presents additional risk to the workers as an uncontained internal arc fault could be initiated during operation of the switchgear while the staff are stood directly opposite the switchboard.

4.2 Option two: offload B zone substation to NR

Under this option, we would offload B zone substation to the nearby North Richmond (**NR**) zone substation.

In order to completely offload our B zone substation, 15 feeders would need to be transferred across to NR. Six of these would be one-to-one feeders, while four would be jumbo feeders which would pick up the other nine feeders from B zone substation. Further works required at our B zone substation would include installing switching cubicles, and cable cutting and jointing work with full remote control of switches and circuit breakers.

The following works would also be required at our NR zone substation:

- install new 27MVA transformer
- install new 66kV circuit breaker
- extend 11kV switch room

- expand bus
- install bus no.5
- install transformer no.4 and new switchgear protection and control
- separate NR into two transformer groups with auto close bus-tie
- associated civils, cable cutting and joining works
- relocate and install two capacitor banks.

The total cost of this work is set out in table 3. These costs are approximately double that required to replace the switchboard at B zone substation (as set out in section 4.3).

Table 3 Option two costs ($million, 2021)

Option two	Costs
Offload B zone substation to NR	14.6

Source: CitiPower

4.3 Option three: replace existing switchboard in the same building

This option includes temporarily offloading and replacing the existing switchboard in the same building. This option would enable the existing substation layout to be retained, and the non-arc fault contained switchboard to be removed from the network.

The scope of works required under this option includes the following:

- install a transportable switchboard, and transfer distribution feeders and transformer incoming cables from the existing switchboard to the portable switchboard
- relocate the transformer protection, communications and pilot wires
- decommission and remove existing switch room and indoor plant, including disposal of hazardous materials
- rebuild switch room according to our technical standards for design and layout, including three double busbar switchboards with a total of 56 circuit breakers, six bus sections and all relevant protection and communications
- transfer distribution feeders to the new switchboard
- reinstate the building and surrounding area affected by the work.

A summary of the costs of this option are shown in table 4.

Table 4 Option three costs ($million, 2019)

Option	Costs
Replace existing switchboard in the same building	8.5

Source: CitiPower

4.4 Option four: non-network solutions

Option four considers the use of load transfers and non-network solutions to defer the need to replace the existing switchboard at B zone substation.

Load transfers

Our existing contingency plans estimate that load transfers could be used at B zone substation to transfer approximately 10.6MVA via 11kV feeders.

Residual energy at risk

With summer peak demand of around 40MVA, the use of 10.6MVA of load transfers would leave residual demand of nearly 30MVA to be met during the summer peak load. Potential demand management solutions may reduce this demand by up to 5MVA.

Meeting an additional 25MVA of demand through a non-network solution(s), however, is expected to be prohibitively expensive (e.g. it would likely require additional at-call generation capacity).

Based on the expected service life of existing generator, photo-voltaic cell and battery storage solutions, an overall period of 20-years is expected before replacement will be necessary.

The implementation of this option would include the decommissioning of the existing switchboard, including proper disposal of hazardous materials such as asbestos and PCBs.

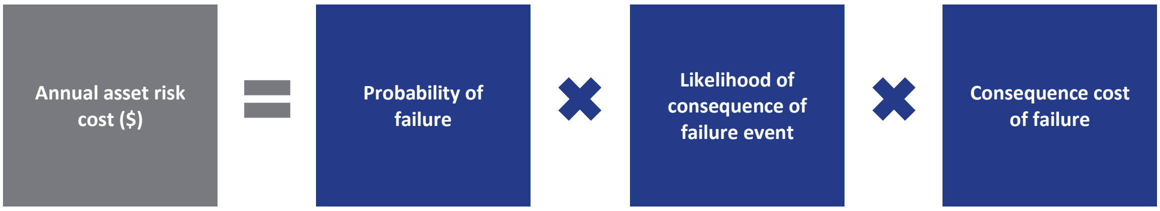
The direct (up-front) cost for this option is considered excessive, with additional ongoing annual running and tariff reduction costs required over the life the solution. It is therefore not considered a viable option.

5 Asset risk monetisation

This section explains our risk monetisation process and how it has been used to inform the timing of our preferred B zone substation investment. Our risk monetisation model is attached with our regulatory proposal.[6]

We monetise risk when assessing investment decisions by determining the annual asset risk cost (as shown in figure 7). This approach is applied to all identified failure modes for an asset, and the sum of the annual asset risk cost for all of failure modes is compared to the annualised cost of the preferred option to determine the economic timing for any intervention. This approach is consistent with the AER's recent asset replacement guidance practice note.[7]

Figure 7 Calculation of annual asset-risk cost



Source: CitiPower

Our approach to risk monetisation employs CBRM to provide a robust methodology for the preparation and application of the required input information (i.e. the probability of failure, and the likelihood and consequence cost of failure).[8] CBRM enables us to use current asset information, engineering knowledge and practical experience to predict future asset condition, performance and risk for our assets. It is a comprehensive management methodology.

5.1 Probability of failure

Asset performance is measured in terms of probability of failure and, for each asset category, is determined by matching the 'health index' profile with recent data on failure rates.

Health indices are derived for individual assets by combining information on age, environment, duty and specific condition information. These indices are then projected forward to reflect the asset's ageing rate, which is dependent on its condition and operating environment.

5.1.1 Determination of health index

The detail of the health index formulation is different for each asset class, reflecting the asset-specific information and degradation processes. There is, however, a consistent approach to determining the health index for all asset classes as shown in figure 8.

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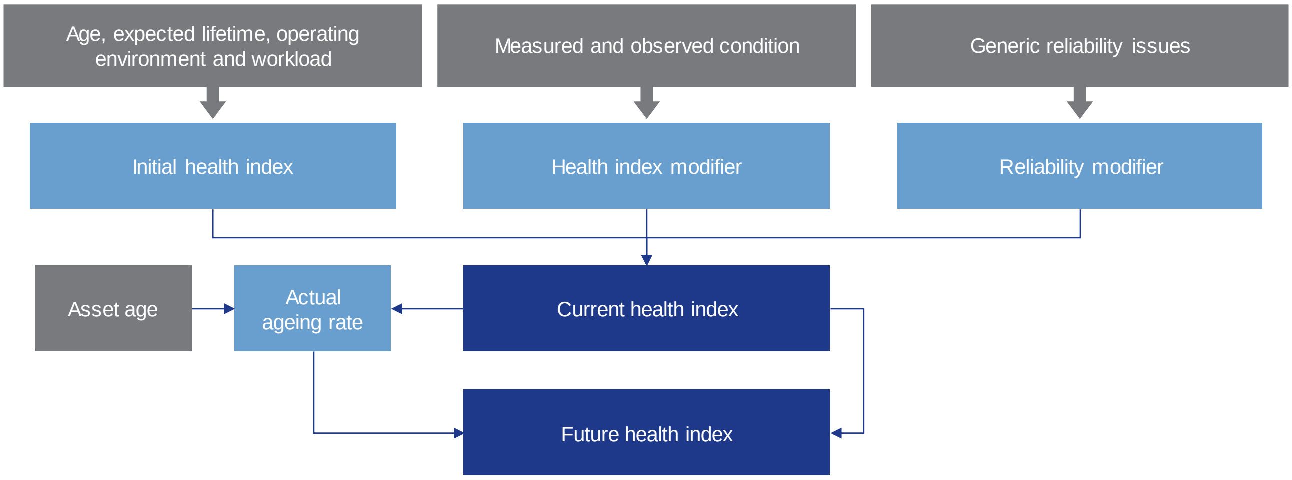
6 CP MOD 4.02 - B supply area - Jan2020 - Public

7 CP ATT175: AER, *Industry practice application note: asset replacement planning*, January 2019.

8 The CBRM is a proprietary model developed by EA Technologies. The model is an ageing algorithm that takes into account a range of inputs to produce a health index for each asset in a range from zero to 10 (where zero is a new asset and 10 represents end of life). The health index provides a means of comparing similar assets in terms of their calculated probability of failure.

Figure 8 Overview of health index determination



Source: EA Technology

An initial health index for our switchboard is calculated using knowledge and experience of the asset's performance and expected lifetime, taking account of factors such as original specification, manufacturer, operational experience and operating conditions (e.g. duty and location).

The initial health index is then adjusted by the health index modifier, which is based on the known condition of the asset. It includes information on condition that is gathered by inspecting the asset, together with information relating to asset defects and failures, and condition information obtained through diagnostic tests.

A reliability modifier can also be applied to modify the current health index to reflect generic issues affecting asset health and/or reliability associated with a manufacturer or model type, or a specific asset performance issue. It can also be used where a specific material or treatment has been applied to the asset. The reliability modifier should be used where there is evidence to show that a sub-group of assets has a materially different probability of failure compared to other assets with the same health index in that asset category.

The current health index, therefore, is derived by modifying the initial health index by the health index modifier and the reliability modifier, subject to upper and lower thresholds derived from the condition and reliability data. Information on the degradation of each asset is then used to 'age' the current health index and thus derive the future health index of each asset.

For our B zone substation, individual health indices for each bus section have been calculated in our CBRM. The individual health indices are set out in table 5.

Table 5 B switchboard: current health indices

Switchboard section	Health index
Bus section no.1	4.33
Bus section no.2	4.33
Bus section no.3	4.33
Bus section no.4	4.82

Source: CitiPower (CBRM)

5.1.2 Determination of probability of failure

The probability of failure is determined by assessing the current condition of the asset and how it will continue to degrade over time. For switchboards, the condition related failure modes that have been derived by considering actual failure data are listed in table 6.

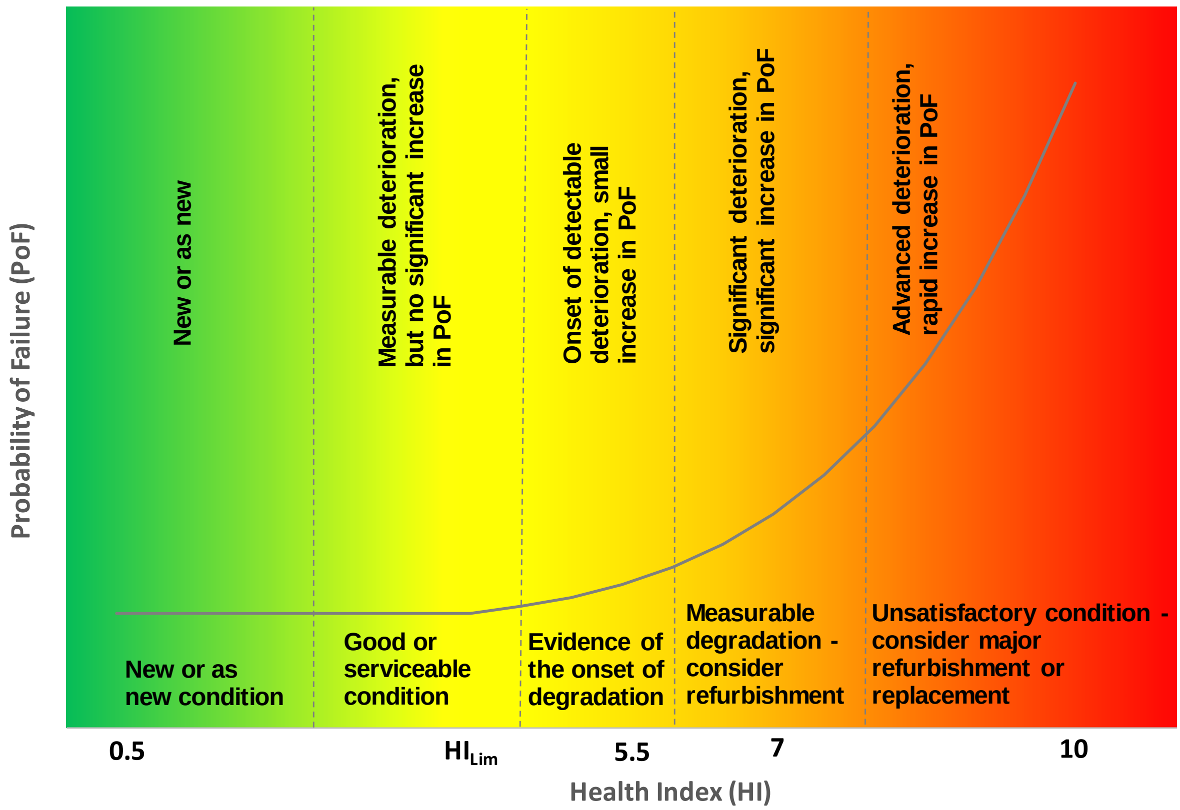
Table 6 Failure mode definitions for switchboards

Failure Mode	Description
Significant	A significant failure which will result in damage to a single bus section and will cause an unplanned outage and require a replacement unit(s) to be installed to restore supply and/or network security
Major	A major failure will which will cause damage to multiple bus sections cause an unplanned outage and require a replacement unit(s) to be installed to restore supply and/or network security

Source: CitiPower

The specific relationship between asset health index and probability of failure is determined by matching the health index profile with the recent failure rate for the asset category. This relationship is not linear. An asset can accommodate significant degradation with very little effect on the probability of failure. Conversely, once the degradation becomes significant or widespread, the risk of failure rapidly increases. The probability of failure of an asset is a function of its health index, as shown in figure 9.

Figure 9 Relationship between health index and probability of failure



Source: EA Technology

Mathematical modelling techniques carried out by EA Technology suggest that a cubic relationship (3rd order polynomial) is appropriate to define the health index and probability of failure relationship as follows:

$$PoF = k \cdot \left(1 + (HI \cdot c) + \frac{(HI \cdot c)^2}{2!} + \frac{(HI \cdot c)^3}{3!}\right)$$ **Equation 1**

where:

PoF	=	probability of failure per annum
HI	=	health index
k & c	=	constants

The value of c fixes the relative values of the probability of failure for different health indices (i.e. the slope of the curve) and k determines the absolute value; both constants are calibration values.

Practical experience has indicated that this cubic relationship is appropriate for assets with higher health indices. However, at low values it has been found that even modest increases in probability of failure defined by the cubic relationship do not fit with actual experience. Therefore, it has become standard practice to adopt a hybrid relationship. Up to a limit value (HI_{Lim}), the probability of failure is set at a constant value; above HI_{Lim} the cubic relationship applies. Experience suggests that HI_{Lim} be set at 4; this is the value that has been used in our evaluation of the transformer replacement program.

Determination of c

The value of c in equation one can be determined by assigning the relative probability of failure values for two health index values (generally HI = 10 and HI = HI_{Lim}). Where reasonably complete information is available that directly relates to the critical degradation processes, there is a fairly high level of confidence in the health indices and, consequently, the relative PoF between the two assets is expected to be high. However, where health indices are predominantly derived from indirect condition related information, leading to a lower level of confidence in the health index, the relative PoF between the two assets is expected to be lower.

In practice, with the use of the hybrid HI / PoF relationship, the value of c is typically set to 1.086, which corresponds to a PoF for an asset with a health index of 10 that is ten times higher than the PoF of a new asset.

Determination of k

The value of k in equation one is determined on the basis of:

- the total observed number of functional failures per annum;
- the health index distribution for the asset category; and
- the volume of assets in the asset category.

The asset group can have a different curve shape and height for each failure mode if it is considered appropriate.

For each asset category, k is calculated as follows:

$$k \cdot \sum_{i=1}^{n} \left(1 + HI_i \cdot c + \frac{(HI_i \cdot c)^2}{2!} + \frac{(HI_i \cdot c)^3}{3!}\right) = (\text{Average no. of failures per annum})_I$$ **Equation 2**

where:

n	=	the number of assets in asset category I
HI_i	=	Health index of asset i

The total experienced failure rate for each failure type is allocated across the asset population based on each asset's health index. Each asset will have a calculated probability for minor, significant and major failures.

Having calculated the health index for each asset, the projected ageing curve can be determined. This projected ageing rate is used to determine the future health index in each year and the resulting probability of failure value for each year.

For our B switchboard, the probability of failure for each failure mode, determined based on the above method, is shown in table 7.

Table 7 B switchboard: probability of failure values (%)

Failure mode	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Major	0.6	0.6	0.6	0.7	0.7	0.8	0.8	0.9	1.0	1.1	1.1	1.2
Significant	5.0	5.3	5.7	6.1	6.6	7.1	7.6	8.2	8.8	9.5	10.3	11.1

Source: CitiPower

5.2 Consequences of failure

Our risk monetisation approach identifies four consequence categories that capture the potential impact on electricity customers of asset failures relating to switchboards. Table 8 shows these risk categories and the associated consequences, each of which can be quantified in dollar terms.

Table 8 Consequence of failure categories and inputs

Consequence category	Consequence inputs
Network performance	• Unserved energy
Safety	• Minor injuries • Serious injuries • Fatality
Financial	• Repair and replacement costs (operating and capital expenditure) • Generation support • Fire brigade attendance
Environmental impact	• Fire starts • Volume of waste produced • Level of disturbance

Source: CitiPower

The calculation of the consequence of failure in our CBRM uses the same failure modes as the probability of failure. For each of these consequence categories, any actual consequences of failure are considered and used to produce a reference cost of failure, which represents the 'typical' impact of a failure based on historical data.

Each of the consequence categories are discussed in further detail below.

5.2.1 Network performance: consequence cost and likelihood

The expected average unserved energy costs are based on the energy at risk, the time at risk, and the value of customer reliability (**VCR**) per megawatt hour. The time at risk is based on the time taken to install generators to restore supply. A weighted average of the 50th and 10th percentile expected unserved energy estimates is calculated by applying weightings of 70% and 30% (respectively).

The unserved energy is initially that which cannot be transferred to alternate supplies following the significant or major failure. This reduces once the generators start to come on line taking account of the number of generators which may be brought on line each day until sufficient generation support has been installed to meet the demand unserved following the initial incident.

The likelihood of consequence is set to 100% on the basis that when a particular failure type occurs it is known to have a particular consequence. For example, as the definition of a significant or a major failure is a failure that results in an outage, and the consequences are determined using actual values of load and capacity, then the likelihood of the consequence occurring must be set to 100%. By definition, these failure modes could not occur without causing loss of the asset and some consequences must occur if there is a significant asset failure.

5.2.2 Safety: consequence cost and likelihood

The safety consequences of failure represent the quantification of the societal value of preventing an accident, serious injury or fatality. The safety consequence for each failure is derived from the reference safety cost of failure used in the CBRM, modified by the probability of a safety consequence occurring.

The safety consequences are estimated with reference to minor, serious and fatal injuries by applying a dollar value that reflects the seriousness of the incident. A 'disproportion factor' is also applied, which recognises that serious and fatal injuries should be avoided even if the costs of doing so outweighs the actuarial value of the loss incurred.

The safety consequence represents the risk that the asset presents to the workforce and public by its characteristics and particular situation. The safety consequence incorporates a measure of the likelihood that someone would be in the vicinity of the asset at the time of failure. The assessment of the safety consequence recognises that staff may be present for routine activities or in response to alarms from monitoring or protection equipment (e.g. partial discharge events or Buchholz relay operation) prior to the asset failure.

The value of the safety consequence of asset failure takes into account the likelihood that a failure of each type would result in injury or death. As the likelihood of the consequence is included in defining the value of consequence, the likelihood of consequence value is set at 100% (otherwise the likelihood of consequence would be double-counted in calculating the expected safety risk).

5.2.3 Financial: consequence cost and likelihood

The financial consequence of failure of an asset is the cost of repair or replacement to return the network to its pre-fault state, and the cost of temporary generation support. As the financial consequences are based on repair or replacement cost, and the failure modes are defined as the need to repair or to replace one or more assets, the likelihood of the defined consequence occurring is 100%.

Replacement costs

The replacement costs of a switchboard are based on recent, observed replacement works on our network. The replacement cost for an asset under failure conditions is assumed within the model to be the same as the planned asset replacement unit cost.

Repair costs

The model also provides for repair costs where the replacement of a switchboard is not considered necessary. The repair costs are most likely to arise for a significant failure mode, rather than major or catastrophic.

Generation costs

The operating costs for generation to supply load when failed assets are replaced or repaired is also considered in the financial consequences.

Generation costs are based on the load at risk and take account of the time to install and remove generators and step-up transformers, the fuel used whilst supplying the load that is not able to be supported within the network, and the costs to supervise and maintain the generators during the period they are deployed.

5.2.4 Environmental: consequence cost and likelihood

The environmental consequences of failure represent the quantification of the potential environmental impacts of failure for each specified failure mode. For each asset, the environmental consequence is derived from the reference environmental cost of failure used in the CBRM, modified by an asset-specific environmental consequence modifier.

A failure has a single outcome and will have 100% likelihood of consequence.

5.2.5 Summary of consequence costs and likelihoods

A summary of the consequence of failure for each failure mode for the B switchboard is set out below.

Table 9 Major failure risk: consequence of failure ($ million, 2021)

Description	Risk value	Likelihood of consequence	Cost of consequence
Expected average unserved energy	21.6	100%	21.6
Safety consequence	0.0	100%	0.0
Generators supplying lost load for duration	15.2	100%	15.2
Install new switchboard and protection	8.4	100%	8.4
Environmental consequence	0.1	100%	0.1
Fire brigade attendance	0.1	100%	0.1

Source: CitiPower

Table 10 Significant failure risk: consequence of failure ($ million, 2021)

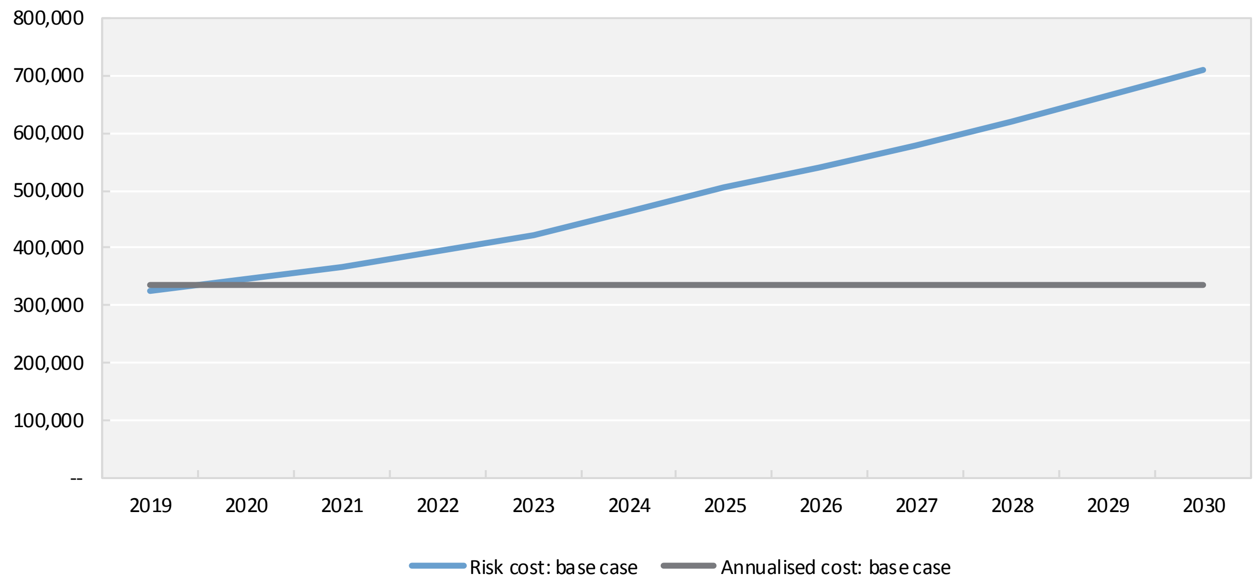
Description	Total risk value	Likelihood of consequence	Cost of consequence
Expected average unserved energy	0.4	100%	0.4
Safety consequence	0.0	100%	0.0
Repair	0.0	100%	0.0
Environmental consequence	0.0	100%	0.0
Fire brigade attendance	0.0	100%	0.0

Source: CitiPower

5.3 Optimal timing of asset replacement

The optimal timing for asset intervention is based on a comparison of the asset risk and the annualised cost of the preferred option. Figure 10 shows this comparison for the base case scenario, which reflects our central input assumptions. Further sensitivity analysis is provided in our risk monetisation model.

Figure 10 B switchboard: comparison of asset risk and annualised cost for base case ($ million, 2021)



Source: CitiPower

Under the base case scenario, the annual asset risk cost is higher than the annualised replacement cost from 2020. We are currently monitoring these risks, but given the rising probability and consequence of failure (as shown by the increase in annualised risk costs over time), asset management intervention is required in the 2021–2026 regulatory period.

6 Recommendation

The preferred option, as set out in section 4, is to replace the existing switchboard in the same building. This approach meets the identified need at the least life-cycle cost.

The forecast capital expenditure requirements for the preferred option for the 2021–2026 period is outlined in table 11.

Table 11 Recommended option: expenditure profile ($million, 2021)

Expenditure forecast	2021/22	2022/23	2023/24	202/254	2025/26	Total
Total capital expenditure	1.19	4.21	3.06	-	-	8.45

Source: CitiPower