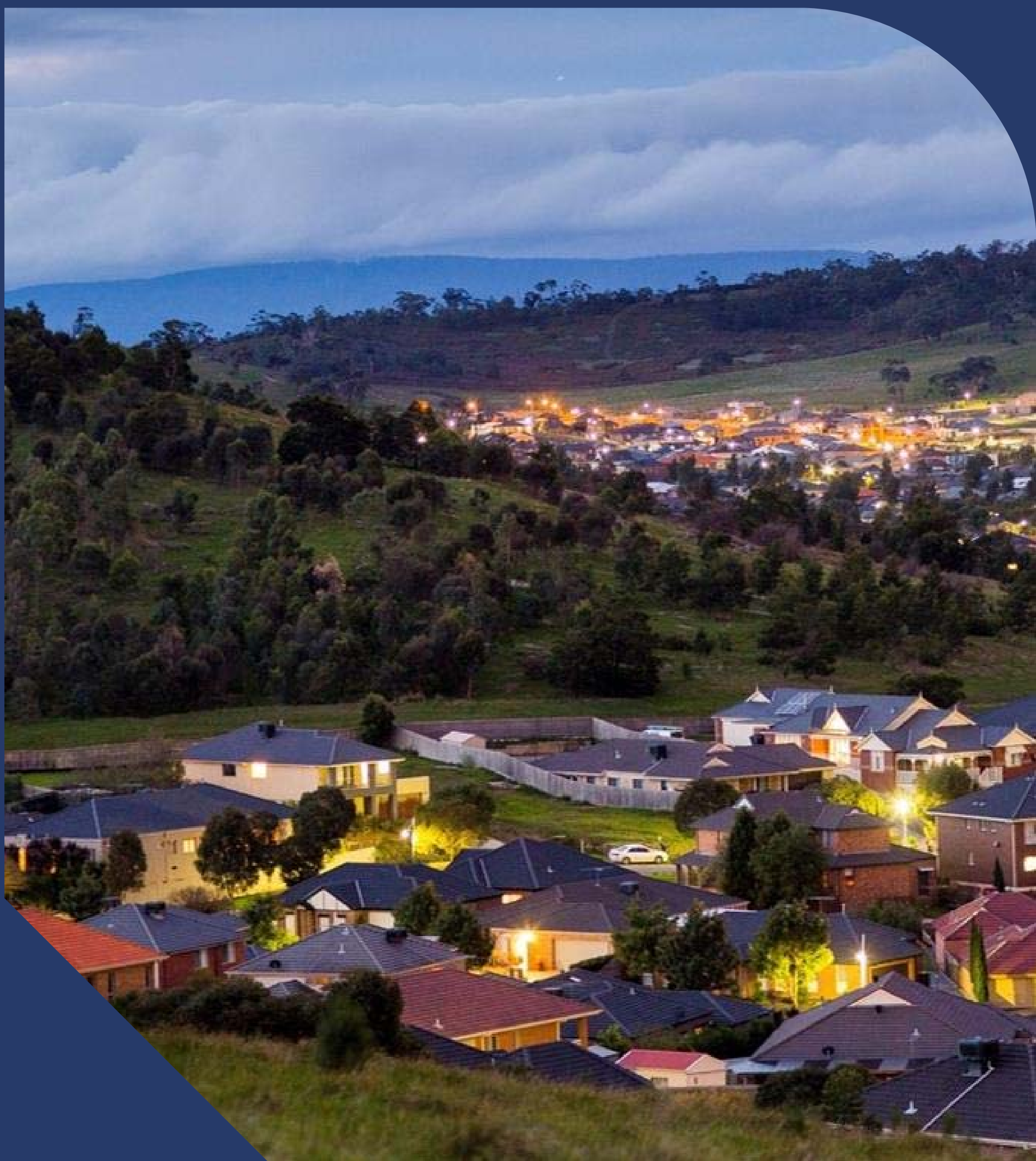
AusNet

Service constraints at Bayswater (BWR) Zone Substation

Regulatory Investment Test for Distribution

Final Project Assessment Report

Monday, 20 February 2023



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1. Executive summary

AusNet is a regulated Victorian Distribution Network Service Provider (DNSP) that supplies electrical distribution services to more than 802,000 customers. Our electricity distribution network covers eastern rural Victoria and the fringe of the northern and eastern Melbourne metropolitan area.

As expected by our customers and required by the various regulatory instruments that we operate under, AusNet aims to maintain service levels at the lowest possible cost to our customers. To achieve this, we develop forward looking plans that aim to maximise the present value of economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

Our planning approach includes the application of a probabilistic planning methodology, under which conditions often exist where some of the load cannot be supplied under rare but possible conditions, such as during extreme demand conditions or with a network element out of service. Where relevant, we also prepare, publish, and consult on a regulatory investment test for distribution (RIT-D), which further helps ensure all credible options are identified and considered, and the best option is selected.

This Final Project Assessment Report (FPAR) is the final stage of the RIT-D in relation to address the existing and emerging service level constraints in the Bayswater Zone Substation (BWR) supply area. The FPAR follows our earlier publication of

- a notice of determination in accordance with clause 5.17.4(d) of the National Electricity Rules (the Rules), which explained that there are no credible non-network options that could address the identified need.
- the Draft Project Assessment Report (DPAR) in relation to this project, which presented cost benefit analysis and invited submissions from stakeholders.

We did not receive any submissions in response to the DPAR.

This FPAR has been prepared by AusNet in accordance with the requirements of clause 5.17 of the Rules. This FPAR complies with the requirements of Clause 5.17.4(r) of the Rules, as detailed in section 7 of this document, and the AER's RIT-D application guidelines.

1.1. Identified Need

BWR commenced operation as a 66/22kV transformation station in the late 1960s with three power transformers and two 66kV lines, one from Ringwood Terminal Station (RWTS) and the other from Boronia Zone Substation (BRA). The third 66kV line was constructed in 2015 and it is a three-legged line from RWTS to Bayswater and Croydon.

The station has an outdoor 22kV switchyard with twin 22kV feeders. There are seventeen 22kV bulk-oil circuit breakers at the station which were installed in the 1960s and 1970s. The station configuration includes three 66kV buses and three 22kV buses. The physical and electrical condition of some assets have deteriorated and are now presenting an increasing failure risk. Approximately 65% of assets at BWR are in poor to very poor condition, C4 and C5 respectively.

The emerging service constraints at BWR are:

- Health and safety risks presented by a possible explosive failure of the bushings on a number of the assets
- Plant collateral damage risks presented by a possible explosive failure of a number of the assets
- Environmental risks associated with insulating oil spill or fire
- Reactive asset replacement risks presented by the increasing likelihood of asset failure due to the deteriorating condition of the assets.

Our assessment is that works are required to address the asset-related risks in accordance with our obligations under clause 5.2 of the Electricity Distribution Code, which requires us to meet reasonable customer expectations of reliability of supply.[1]

[1] For further details of the regulatory obligation that underpin the identified needs at BWR, please refer to section 4 of the notice of determination published on 21 April 2021.

1.2. Options considered and preferred option

The options considered in this FPAR, which include both credible and non-credible options, are:

1. ‘Do nothing’ or Business as Usual
2. Retire one transformer
3. Retire one transformer and reduce residual risk through network support
4. Use network support to defer retirement and replacement
5. Replace all 22kV switchgear
6. Replace one transformer and 22kV switchgear
7. Replace two transformers and 22kV switchgear.

Our analysis concludes that only Options 5, 6 and 7 are credible options, and the preferred option is Option 5.

1.3. Contact details

Any questions regarding this report should be directed to:

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2. Background

2.1. Location and conditions

BWR is located in the eastern suburbs of metropolitan Melbourne approximately 29km east of Melbourne and is the main source of supply for the suburbs of Bayswater, Croydon South, Kilsyth South, Wantirna and Heathmont. BWR supplies approximately 17,700 AusNet customers. The load at BWR includes mostly residential and commercial urban load with some industrial loads.

BWR has a typical Melbourne climate with summer average maximum temperatures of 26°C, winter average minimum temperatures of 6°C with extreme temperatures reaching 46°C in summer and -3°C in winter. The average rainfall is 658mm in this area.

BWR is supplied at 66kV via three 66kV circuits that originate from Ringwood Terminal Station (RWTS), Boronia Zone Substation (BRA) and a three-legged line from RWTS to Bayswater and Croydon.

The location of BWR within the AusNet distribution network is as shown in the figure below.

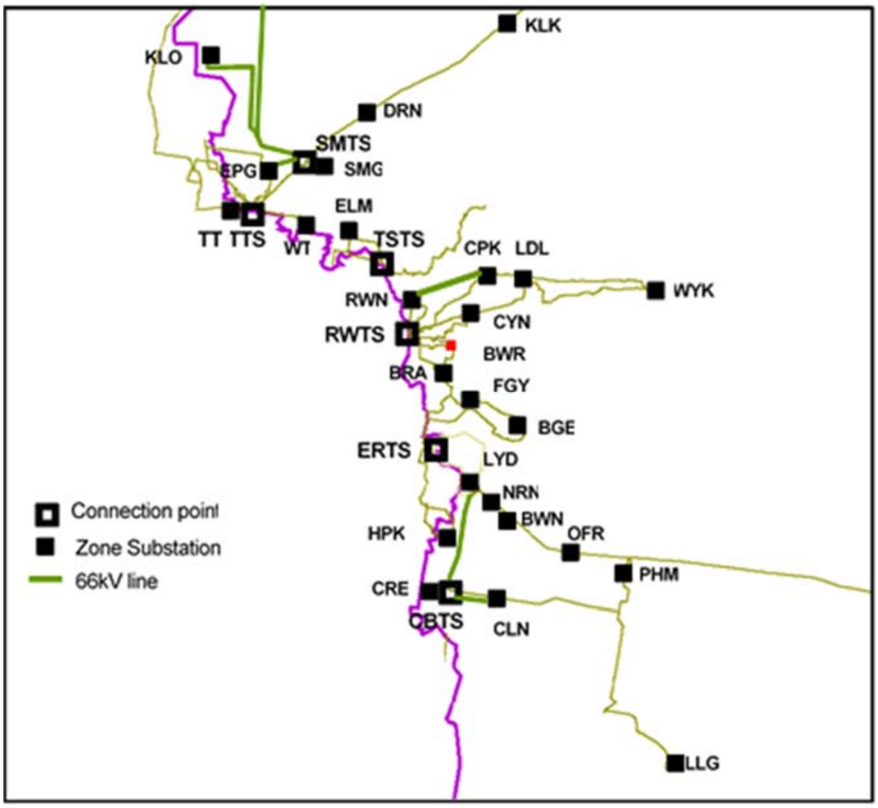

Figure 1: BWR location within AusNet distribution network

2.2. Customer Composition

BWR has ten 22kV feeders of which supply into the AusNet supply area. The table below provides details of the 22 kV supply feeders.

Table 1: BWR feeder information

Feeder	Feeder Length (km)	Feeder description	Number of Customers	Customer Type
BWR12	6.5	Summer peaking, urban feeder	789	25% residential 36% commercial 39% industrial 0% farming
BWR13	40.0	Summer peaking, short rural feeder	4,480	92% residential 5% commercial 3% industrial 0% farming
BWR14	1.2	Summer peaking, urban feeder	1	100% commercial
BWR21	1.2	Summer peaking, urban feeder	1	100% commercial
BWR22	10.3	Summer peaking, urban feeder	1,069	45% residential 24% commercial 31% industrial 0% farming
BWR23	19.7	Summer peaking, urban feeder	3,680	92% residential 5% commercial 3% industrial 0% farming
BWR24	8.8	Summer peaking, urban feeder	780	51% residential 33% commercial 16% industrial 0% farming
BWR32	2.9	Summer peaking, urban feeder	2,920	89% residential 8% commercial 3% industrial 0% farming
BWR33	1.2	Summer peaking, urban feeder	96	3% residential 54% commercial 43% industrial 0% farming
BWR34	1.7	Summer peaking, urban feeder	3,170	86% residential 13% commercial 1% industrial 0% farming

The 22kV feeders interconnect with 22kV feeders from Boronia Zone Substation (BRA), Ringwood Terminal Station (RWTS) and Croydon Zone Substation, providing a load transfer capability of 23.8MVA.

2.3. Zone Substation equipment

2.3.1. Primary Equipment

BWR includes an air-insulated 66kV switchyard with three 66kV buses separated by bus-tie circuit breakers connected to three incoming 66kV lines from RWTS and BRA.

There are three 22kV air insulated busbars connected to one another with a bus-tie circuit breaker and connected to the three 66/22kV transformers via three transformer circuit breakers. Ten 22kV feeders and one 6MVAr and one 12MVAr capacitor banks are connected to these 22kV busbars.

The 22kV switchyard currently has sixteen 22kV bulk oil circuit breakers which have been assessed as being in C4 and C5 condition. The BWR32 22kV feeders circuit breaker is rated at C3.

Transformation comprises three 20/27MVA 66/22kV transformers located in the No.1, No.2 and No.3 positions, with two manufactured by Wilson rated at C4 and the other manufactured by English Electric rated at C3 and installed at BWR in the late 1960s.

2.3.2. Secondary Equipment

The three incoming 66kV lines and buses are protected by current differential and remote trip send and directional overcurrent protection using modern SEL 411L and GE F650 relays.

The No.1, No.2 and No.3 66/22kV transformer differential protection is provided by new transformer differential protection ABB D21SE2 relays.

The 22kV bus protection consists of high impedance bus protection and bus distance protection using GEC - CDG14 and GE - 30 relays.

The 22kV feeder circuit breakers have master earth fault and back up earth fault protection using older Email - Group, SR 760 and ABB - Group relays.

The 22kV capacitor bank protection has overcurrent, earth fault and voltage balance schemes using a GE - 650 relay.

The station has duplicated 22/0.415kV AC systems and battery chargers that supply a 125V DC system for the protection relays and trip coils.

2.3.3. Single line diagram

The configuration of primary electrical circuits within BWR is as shown in the single line diagram in Figure 2.

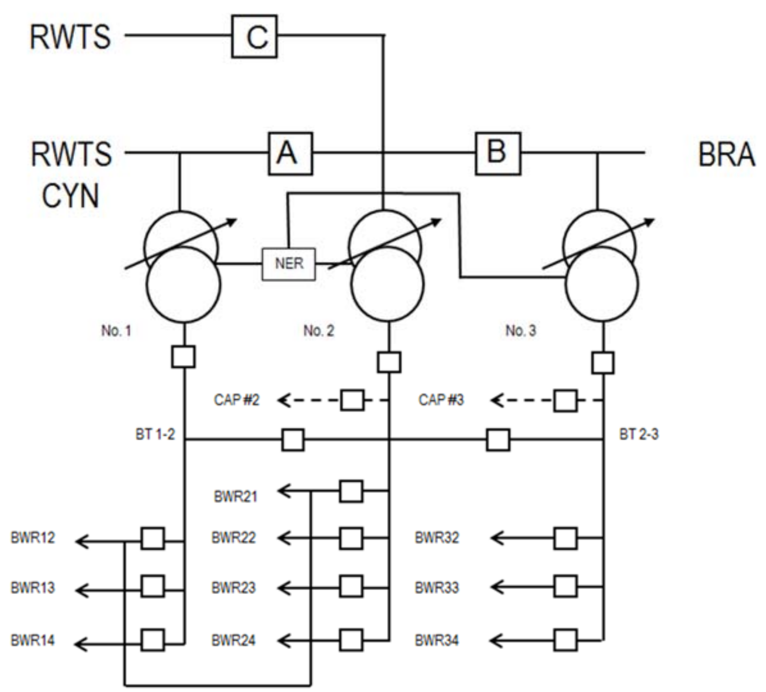

Figure 2: BWR Single Line Diagram

3. Identified need

BWR commenced operation as a 66/22kV transformation station in the late 1960s with three power transformers and two 66kV lines, one from Ringwood Terminal Station (RWTS) and the other from Boronia Zone Substation (BRA). The third 66kV line was constructed in 2015 and it is a three-legged line from RWTS to Bayswater and Croydon.

The station has an outdoor 22kV switchyard with twin 22kV feeders. There are seventeen 22kV bulk-oil circuit breakers at the station which were installed in the 1960s and 1970s. The station configuration includes three 66kV buses and three 22kV buses. The physical and electrical condition of some assets have deteriorated and are now presenting an increasing failure risk. Approximately 65% of assets at BWR are in poor to very poor condition, C4 and C5 respectively.

The emerging service constraints at BWR are:

- Health and safety risks presented by a possible explosive failure of the bushings on a number of the assets
- Plant collateral damage risks presented by a possible explosive failure of a number of the assets
- Environmental risks associated with insulating oil spill or fire
- Reactive asset replacement risks presented by the increasing likelihood of asset failure due to the deteriorating condition of the assets.

The condition of the assets at BWR is discussed in the Asset Health Reports for the key asset classes such as power transformers, instrument transformers and switchgear with information on asset condition rankings, recommended risk mitigation options and replacement timeframes. In light of our Asset Health Report for BWR, our assessment is that works are required to address the asset-related risks in accordance with our obligations under clause 5.2 of the Electricity Distribution Code, which requires us to meet reasonable customer expectations of reliability of supply.

Our planning report for BWR also highlighted the security of supply risks that arise from the station configuration and asset failure. Our updated load forecasts indicate that supply risks do not arise, other than as a result of station configuration. The load at risk as a result of this station configuration issue is an additional factor that will need to be considered in assessing the credible options.

4. Assumptions underpinning the identified need

The purpose of this section is to summarise the key input assumptions that underpin the identified need described in the previous section.

4.1. Regulatory obligations

In addressing the identified need, we must satisfy our regulatory obligations, which we summarise below.

Clause 6.5.7 of the National Electricity Rules requires AusNet to only propose capital expenditure required to achieve each of the following:

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) quality, reliability or security of supply of standard control services; or

(ii) the reliability or security of the distribution system through the supply of standard control services

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control services, and

(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services.

Section 98(a) of the Electricity Safety Act requires AusNet to design, construct, operate, maintain and decommission its supply network to minimise as far as practicable:

(a) the hazards and risks to the safety of any person arising from the supply network; and

(b) the hazards and risks of damage to the property of any person arising from the supply network; and

(c) the bushfire danger arising from the supply network.

The Electricity Safety act defines 'practicable' to mean having regard to –

(a) severity of the hazard or risk in question; and

(b) state of knowledge about the hazard or risk and any ways of removing or mitigating the hazard or risk; and

(c) availability and suitability of ways to remove or mitigate the hazard or risk; and

(d) cost of removing or mitigating the hazard or risk.

Clause 19.2.1 of the Electricity Distribution Code of Practice requires AusNet to:

develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of its distribution system assets and plans for the establishment and augmentation of transmission connections:

(i) to comply with the laws and other performance obligations which apply to the provision of distribution services including those contained in this Code of Practice;

(ii) to minimise the risks associated with the failure or reduced performance of assets; and

(iii) in a way which minimises costs to customers taking into account distribution losses.

Under clause 13.3 of the Electricity Distribution Code of Practice, AusNet:

must use best endeavours to meet targets determined by the AER in the current distribution determination and targets published under clause 13.2.1 and otherwise meet reasonable customer expectations of reliability of supply.

4.2. Asset condition

AMS 10-13 Condition Monitoring describes AusNet's strategy and approach to monitoring the condition of assets. Asset condition is measured with reference to an asset health index on a scale of C1 to C5. The condition scores are used to calculate the asset failure rates using the Weibull parameters determined for each asset class. Table 2 below provides a description of the asset condition scores.

Table 2: Asset Condition Score and Remaining Service Potential

Condition Score	Condition	Condition Description
C1	Very Good	Initial service condition
C2	Good	Deterioration has minimal impact on asset performance. Minimal short term asset failure risk.
C3	Average	Functionally sound showing some wear with minor failures, but asset still functions safely at adequate level of service.
C4	Poor	Advanced deterioration – plant and components function but require a high level of maintenance to remain operational.
C5	Very Poor	Extreme deterioration approaching end of life with failure imminent.

The condition of the key assets at BWR is discussed in the Asset Health Reports for the key asset classes such as power transformers, instrument transformers and switchgear with information on asset condition rankings, recommended risk mitigation options and replacement timeframes. A summary of the asset condition at BWR is provided in Table 3 below and discussed in the following sections.

Table 3: Asset Condition Score and Remaining Service Potential

	Number of assets by Condition Score				
Condition Score	C1	C2	C3	C4	C5
66kV Circuit Breakers	3				
66kV Current Transformers					3
66kV Voltage Transformers	3				2
66/22kV Power Transformers			1	2	
22kV Circuit Breakers			2	9	7
22kV Current Transformers	1				1
22kV Voltage Transformers		3			

These condition scores are then used to calculate the asset failure rates using the Weibull parameters determined for each asset class.

4.3. Zone Substation Supply Capacity

BWR is a summer peaking station and the peak electrical demand reached 48.2MVA in the summer of 2020/21. The demand at BWR is forecast to increase slowly at a growth rate of less than 0.5% per annum. The figure below shows the forecast maximum demand and supply capacities (cyclic ratings) for BWR.

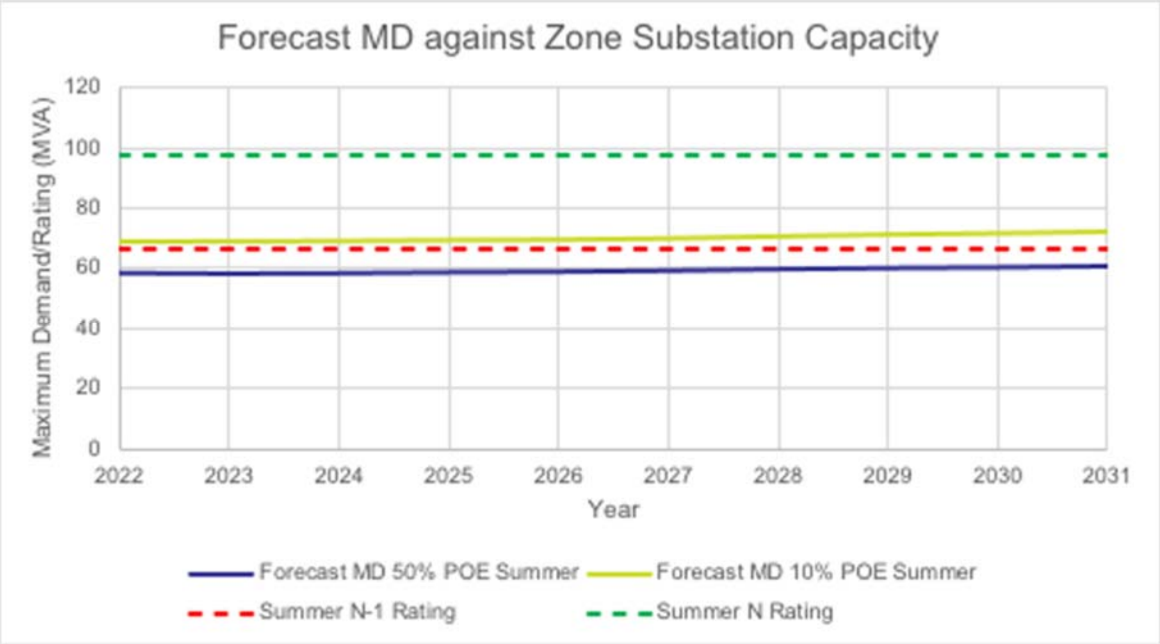

Figure 3: BWR Forecast Maximum Demand against Zone Substation Capacity

4.4. Load Duration Curves

The zone substation load duration curves that feed into the risk-cost assessment model are derived from historical actual demands. The historical hourly demands are separated by season and unitised based on the recorded maximum demand within that season (summer and winter) and time period, which allows the load duration curve to be scaled according to the seasonal forecast maximum demand for each year of the assessment period.

The 50% POE unitised load duration for BWR is presented in Figure 4, and the 10% POE unitised load duration for BWR is presented in Figure 5.

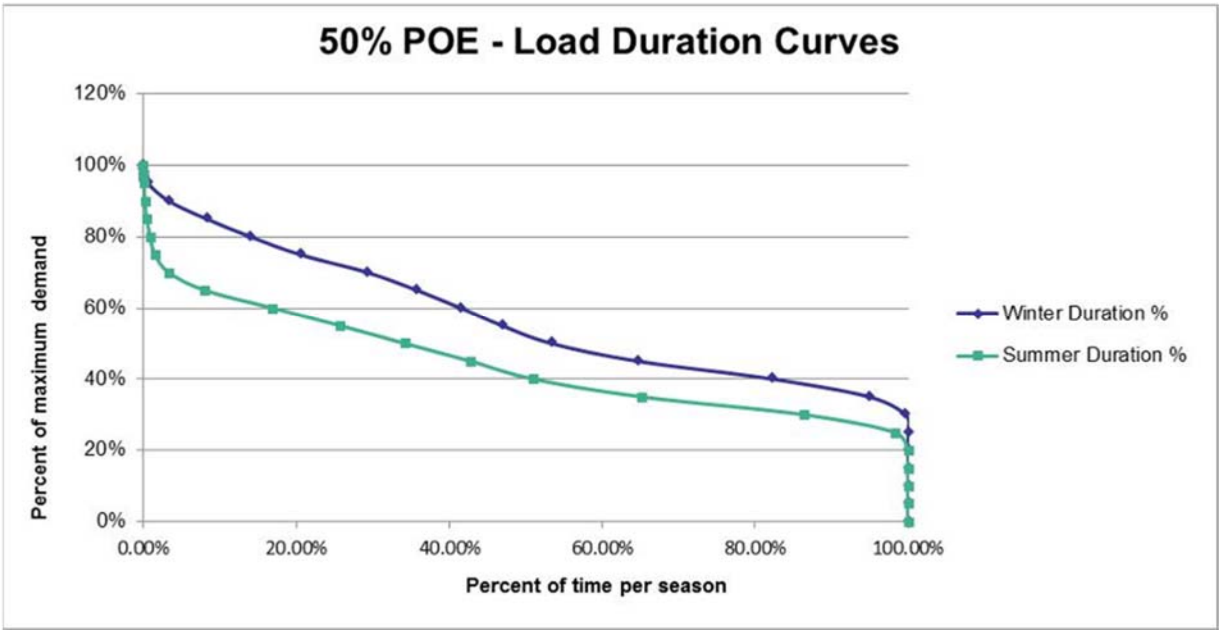

Figure 4: BWR 50% Load Duration Curves

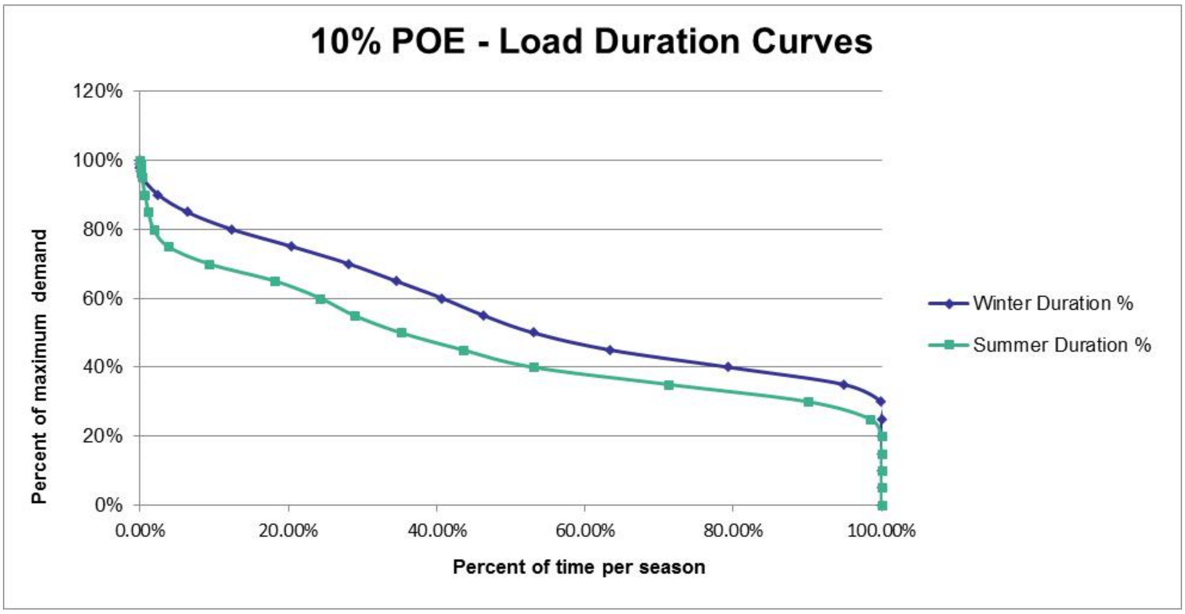

Figure 5: BWR 10% Load Duration Curves

4.5. Feeder Circuit Supply Capacity

There is currently no requirement for additional feeders at BWR due to the modest load growth expected in the supply area.

4.6. Load Transfer Capability

The Distribution Annual Planning Report provides the load transfer capability (in MW) of the feeder interconnections between BWR and its neighbouring zone substations. The load transfer capability of the feeder interconnections between BWR and its neighbouring zone substations is 23.8 MVA.[2]

2 AusNet, Distribution Annual Planning Report 2023 – 2027, December 2023, pages 54 and 56.

5. Potential Credible Options

This section outlines the potential options that have been considered to address the identified need, and summarises the key works and costs associated with implementing these options. In subsequent analysis some of these options have been found not to be credible but are nevertheless included here for completeness.

The following options were considered in seeking to address the identified need at BWR:

1. Do nothing or Business as Usual
2. Retire one transformer
3. Retire one transformer and reduce residual risk through network support
4. Network support to defer retirement and replacement
5. Replace all 22kV switchgear
6. Replace one transformer and 22kV switchgear
7. Replace two transformers and 22kV switchgear.

These options are unchanged from those considered in the DPAR. The costs presented in this section are expressed in real 2022 dollars.

5.1. Option 1: Do Nothing or BAU

This (counterfactual) option assumes that AusNet would not undertake any investment, outside of the normal operational and maintenance processes. Under this option, increasing supply risk would be managed by increased levels of involuntary load reduction. Increased non-supply risks, such as those associated with safety, collateral damage, reactive replacement and environmental impacts, would be accepted as unmanaged rising risk costs.

The Business as Usual (counterfactual) option establishes the base level of risk (and associated costs), and provides a basis for comparing potential options to address the identified need.

5.2. Option 2: Retire one transformer

This option tests whether the current installed capacity of the substation is still required to meet customer demand and whether equipment could be retired rather than replaced.

Our analysis shows that this option would increase the expected unserved energy and would produce a negative net present value (NPV) compared to the 'Business as Usual' option. Furthermore, the retirement of one transformer would not address the asset-related risks described in the identified need. On that basis, this option is not credible and is not considered further.

5.3. Option 3: Retire one transformer and reduce residual risk through network support

This option supplements Option 2 by examining whether the addition of network support would provide a cost-effective means of eliminating residual risk and therefore produce a higher net market benefit.

Our analysis suggests that network support could reduce the cost of unserved energy that would arise under Option 2, but it would continue to produce an inferior outcome compared to the 'Business as Usual' option. In addition, it would also fail to address the asset-related risks that are described in the identified need.

For these reasons, this option is not credible and is not considered further.

5.4. Option 4: Network support to defer retirement and replacement

This option extends Option 3 to consider whether sufficient network support could be provided to avoid entirely the proposed retirement and replacement of the network assets, i.e. a network support only solution.

For the reasons set out in relation to Options 2 and 3, this option is not credible as it would fail to address the asset-related risks that are described in the identified need. For further information, please refer to our notice of determination, which explained that there are no credible non-network options that are capable of addressing the identified need at BWR.

5.5. Option 5: Replace all 22kV switchgear

This option replaces all existing deteriorated outdoor 22kV bulk oil circuit breakers in C4 and C5 condition with three new indoor switchboards and associated secondary equipment within the new control building. This option does not address the risks associated with the 66/22kV power transformers.

The estimated capital cost for this option is $20.5 million in real 2022 dollars, including an allowance for management reserve and risk.

5.6. Option 6: Replace one transformer and 22kV switchgear

In addition to replacing all 22kV circuit breakers as per Option 5, this option also replaces No.2 66/22kV power transformer. Under this option, No.1 66/22kV power transformer will be replaced seven years after the completion of stage 1, and therefore this option does not immediately address the risks associated with this power transformer.

The estimated capital cost of this option is $23.39 million in real 2022 dollars.

5.7. Option 7: Replace two transformers and 22kV switchgear

This option extends Option 6 by also replacing the No.1 and No.2 66/22kV power transformer.

The estimated capital cost of this option is $26.81 million in real 2022 dollars.

6. Economic assessment of the credible options

6.1. Market benefit

The regulatory investment test for distribution requires the RIT-D proponent to consider whether each credible option provides the classes of market benefits described in clause 5.17.1(c)(4) of the Rules. To address this requirement, the table below discusses our approach to each of the market benefits listed in clause 5.17.1(c)(4) in assessing the credible options to address the identified need relating to the emerging service constraints at BWR.

Table 4: Analysis of Market Benefits

Class of Market Benefit	Analysis
(i) changes in voluntary load curtailment;	The options are not expected to lead to changes in voluntary load curtailment.
(ii) changes in involuntary load shedding and customer interruptions caused by network outages, using a reasonable forecast of the value of electricity to customers;	The options are expected to have an impact on involuntary load shedding, although the identified need relates to asset condition. The cost benefit analysis will therefore consider the impact of each option on load shedding. AusNet applies probabilistic planning techniques to assess the expected cost of unserved energy for each option.
(iii) changes in costs for parties, other than the RIT-D proponent, due to differences in: *(A) the timing of new plant;* *(B) capital costs; and* *(C) the operating and maintenance costs;*	There is no impact on other parties.
(iv) differences in the timing of expenditure;	This project will not result in changes in the timing of other expenditure.
(v) changes in load transfer capacity and the capacity of Embedded Generators to take up load;	This project will not impact on the capacity of Embedded Generators to take up load.
(vi) any additional option value (where this value has not already been included in the other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the National Electricity Market;	This project will not impact the option value with respect to likely future investment needs of the NEM.
(vii) changes in electrical energy losses; and	This project will not result in changes to electrical energy losses.
(viii) any other class of market benefit determined to be relevant by the AER.	We do not consider any other class of market benefit as relevant to the selection of the preferred option.

6.2. Methodology

The purpose of this section is to provide a high-level explanation of our methodology for identifying the preferred option. As a general principle, it is important that the methodology takes account of the identified need and the factors that are likely to influence the choice of the preferred option. As such, the methodology is not a 'one size fits all' approach, but one that is tailored for the particular circumstances under consideration.

The identified need for this project can be described in terms of two types of risk:

- supply risk, where an asset failure may lead to a loss of supply to customers; and
- non-supply risk, which captures the potential consequences of an asset failure, which may include safety and environmental costs, in addition to damage to adjacent assets or property.

In relation to supply risk, we adopt a probabilistic planning methodology which considers the likelihood and severity of critical network conditions and outages. The expected annual cost to customers associated with supply risk is calculated by multiplying the expected unserved energy (the expected energy not supplied based on the probability of the supply constraint occurring in a year) by the value of customer reliability (VCR).

In relation to non-supply risks, our approach monetises this risk by multiplying the following parameter estimates:

- the probability of asset failure;
- the cost of the consequence of the asset failure;
- the likelihood of the consequence given the failure has occurred; and
- the number of assets to which the analysis relates.

The purpose of the cost benefit analysis that underpins the RIT-D assessment is to determine whether there is a cost-effective option to mitigate the supply and non-supply risks (the aggregate 'risk-cost'). To be cost-effective, the reduction in the aggregate risk-cost that an option is expected to provide must exceed the cost of implementing that option. The preferred option provides greatest expected net benefit, expressed in present value terms.

In the absence of remedial action,

Figure 6 shows how the aggregate risk-cost will typically increase as the risk of asset failure and energy at risk increase over time. The optimal timing of the preferred option occurs when the annualised capital cost of that option (or the operating cost for a non-network option) is equal to the aggregate risk-cost.

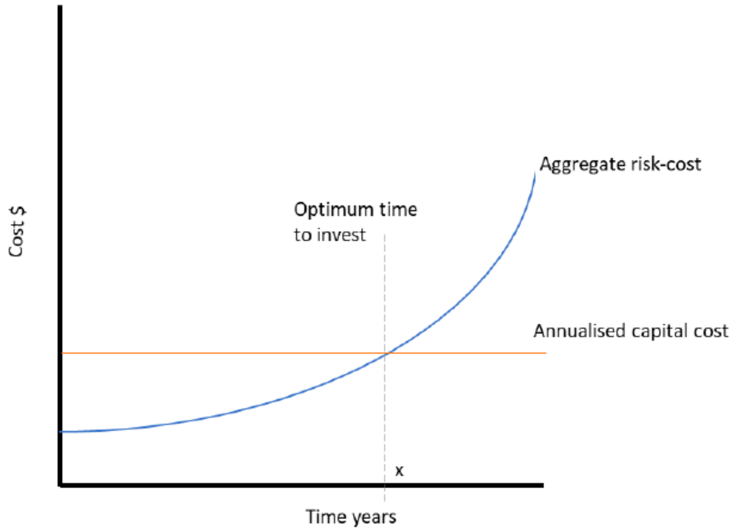

Figure 6: Increasing risk-cost over time and optimal project timing[3]

In effect, the preferred option delivers the lowest total cost to customers, which is the sum of the cost of implementing that option and any residual risk-cost. The identification of the preferred option is complicated by the fact that the future is uncertain and that various input parameters are 'best estimates' rather than known values. Therefore, the RIT-D analysis must be conducted in the face of uncertainty.

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3 This figure is reproduced from the AER's Industry practice application note, Asset replacement planning, January 2019, figure 8. This figure assumes that the option eliminates the aggregate risk-cost in full, which may not be the case.

To address uncertainty in our assessment of the credible options, we use sensitivity analysis and scenario analysis in our cost benefit assessment. As recommended by the AER's application guidelines, we use sensitivity analysis to assist in determining an appropriate set of reasonable scenarios.[4] The relationship between sensitivity analysis and scenarios is best explained by the AER's practice note:[5]

> *Scenarios should be constructed to express a reasonable set of internally consistent possible future states of the world. Each scenario enables consideration of the prudent and efficient investment option (or set of options) that deliver the service levels required in that scenario at the most efficient long run service cost consistent with the National Electricity Objective (NEO).*
>
> *Sensitivity analysis enables understanding of which input values (variables) are the most determinant in selecting the preferred option (or set of options). By understanding the sensitivity of the options model to the input values a greater focus can be placed on refining and evidencing the key input values. Generally the more sensitive the model output is to a key input value, the more value there is in refining and evidencing the associated assumptions and choice of value.*
>
> *Scenario and sensitivity analyses should be used to demonstrate that the proposed solution is robust for a reasonable range of futures and for a reasonable range of positive and negative variations in key input assumptions. NSPs should explain the rationale for the selection of the key input assumptions and the variations applied to the analysis.*

In applying sensitivities and scenarios to our cost benefit assessment, we have regard to the particular circumstances to ensure that the approach is appropriate. Where our analysis shows that an option is clearly preferred, we will not undertake further testing. This approach is consistent with clause 5.17.1(c)(2) of the Rules, which states that the RIT–D must not require a level of analysis that is disproportionate to the scale and likely impact of each credible option considered.

In preparing the RIT-D, we have also had regard to AEMO's 2021 Inputs, Assumptions and Scenarios Report and its 2022 Integrated System Plan (ISP). We note that the scenarios adopted by AEMO are focused particularly on the matters that are relevant to major transmission investments, rather than distribution investments of the type considered in this report. Accordingly, we have adopted an approach that is appropriate to the specific circumstances described in this report relating to the identified need and the credible options.

6.3. Key variables and assumptions

Table 5 below lists the key variables and assumptions applied in the economic assessment, which are essential inputs to our methodology described above. The table also sets out the upper and lower bounds of the range of forecasts adopted for each of these variables. As explained above, the lower bound and upper bound estimates are used to undertake sensitivity testing and scenario analysis. The detailed results of this modelling are provided in section 6.4.

Table 5: Key variables and assumptions

Variable / assumption	Lower bound	Central estimate	Upper bound
Demand forecasts	5% reduction in central estimate of annual growth rate	Forecast average annual growth rate of 0.5%	5% increase in central estimate of annual growth rate
Cost of involuntary supply interruption	25% reduction in central estimate	Value of Customer Reliability (VCR) of $47,888 per MWh[6]	25% increase in central estimate
Safety cost	Central Estimate	Value of statistical life of $4.5 million[7]	Central estimate
Safety cost Disproportionate Factor	Central estimate	Factor of 3	Central estimate
Option cost	15% reduction in central estimate	In-house cost estimates using detailed and high-level project scopes	15% increase in central estimate

4 AER, Application guidelines, Regulatory investment test for distribution, December 2018, page 42.
5 AER, Asset replacement planning, January 2019, page 36.
6 Calculated using the latest VCR estimates for each sector.
7 Best Practice Regulation Guidance Note Value of statistical life, December 2014, escalated.

Variable / assumption	Lower bound	Central estimate	Upper bound
Real discount rate per annum[8]	2.0%	5.5%	7.5%
Probability of asset failure	25% reduction in central estimate	Historical asset performance data, plus forecasts based on condition monitoring and CBRM modelling	25% increase in central estimate

Source: AusNet

6.4. Cost benefit analysis

The economic analysis presented below allows comparison of the economic cost and benefits of each option to rank the options and to determine the optimal timing of the preferred option. It quantifies the capital costs and the cost of the residual risk for each option, to determine a total cost for each option. The net economic benefit for each credible option is the total cost associated with that option minus the costs of the 'Business as Usual' option.

As each of the credible options involves the replacement of existing assets, we have assumed that the operating cost for each option is unchanged from the 'Business as Usual' option. For the purpose of this RIT-D, we consider this approach to be a reasonable working assumption. The capital cost for each option has been described in section 5 of this FPAR.

We present our analysis as follows

- Section 6.4.1 presents the NPV analysis using central estimates; and
- Section 6.4.2 presents the sensitivity testing and scenarios analysis.

6.4.1. Present value analysis using central estimates

Table 6 presents the annualised net economic benefit of each credible option for each year and highlights the option with the highest net economic benefit, assuming the central estimates for the key variables presented in the previous section. For each option, we have selected the optimal timing or indicated for some options that the solution will not deliver a net benefit over the study period.

It should be noted that a residual risk-cost and benefit also applies for each option, which captures the costs and benefits beyond 2031. We have not shown the residual costs and benefits for each option in the table below, but this is considered in our PV analysis which is reported later in this section.

Table 6: Annualised net economic benefit ($M)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Option 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Option 2	This option is no longer considered credible, as explained in section 5.2.									
Option 3	This option is no longer considered credible, as explained in section 5.3.									
Option 4	This option is no longer considered credible, as explained in section 5.4.									
Option 5	0.000	0.301	0.412	0.528	0.649	0.776	0.908	1.042	1.180	1.323
Option 6	0.000	0.111	0.227	0.348	0.474	0.606	0.744	0.884	1.027	1.176
Option 7	0.000	0.000	0.101	0.227	0.358	0.495	0.639	0.784	0.933	1.088

Source: AusNet

8 The discount rates are consistent with AEMO's 2021 Inputs, Assumptions and Scenarios Report.

As shown in the table above, Options 2, 3 and 4 are no longer considered to be credible options and are not considered further in this RIT-D assessment. Of the remaining options, Option 5 provides greater net benefits in each year to 2031.

While the above table is useful in understanding how the options compare with one another in the early years following their implementation, the analysis required by the RIT-D must consider the relative performance of the credible options over the life of the asset. Accordingly, the following table shows that the present value of the net costs and benefits for each option over its life, using our central estimates, based on the optimal timing for each option.

Table 7: Net economic benefit ($M)[9]

	PV of risk reduction benefit	PV of Option costs	PV of net economic benefit
Option 1	0.0	0.0	0.0
Option 2	Not a credible option		
Option 3	Not a credible option		
Option 4	Not a credible option		
Option 5	35.40	18.30	17.10
Option 6	37.15	22.56	14.59
Option 7	37.36	24.32	13.04

Source: AusNet

The present value analysis in Table 7 shows that Option 5 is preferred to the remaining credible options and the 'Business as Usual' option because it delivers the highest expected net benefit over the expected life of the investment, based on our central estimates.

6.4.2. Sensitivity testing and scenario analysis

As explained in section 6.2, we undertake sensitivity testing to examine how the net benefit for each option would be affected if certain parameters were varied. In this instance, we considered variations in the risk of asset failure; demand; the cost of each option; and the discount rate. The results of this analysis are presented below.

Table 8: Net benefit - sensitivity testing ($M)

	High asset failure	Low asset failure	High demand	Low demand	High option cost	Low option cost	High discount rate	Low discount rate
Option 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Option 2	Not a credible option							
Option 3	Not a credible option							
Option 4	Not a credible option							
Option 5	36.97	2.54	18.42	15.79	14.36	19.85	8.45	31.16
Option 6	35.43	0.45	15.96	13.26	11.30	17.97	5.98	29.31
Option 7	34.83	N/A	14.41	11.75	9.53	16.90	4.57	28.41

Source: AusNet

The sensitivity analysis shows that Option 5 continues to deliver a net benefit against each of these changes in parameter assumptions, which provides strong assurance that the project delivers a net benefit across a broad

9 The costs include an allowance for management reserve and risk.

range of different parameter inputs. To test our results further, we have adopted four scenarios, as set out below. In our view, these scenarios comply with the requirements of the RIT-D application guidelines, noting that they describe different sets of states of the world that are relevant to the investment decision. The current ISP scenarios – which relate principally to changes in the wholesale generation market – are not relevant to this investment decision.

Table 9: Definition of reasonable scenarios

Scenario	Probability of failure	Option Cost	Forecast Demand	VCR	Discount rate
Central Case	Central estimate	Central estimate	Central estimate	Central estimate	Central estimate
Low demand	Central estimate	Central estimate	Lower bound	Central estimate	Central estimate
Weak economic growth	Central estimate	Lower bound	Lower bound	Central estimate	Lower bound
High demand	Central estimate	Upper bound	Upper bound	Central estimate	Upper bound

Table 10 below provides a brief description of each scenario.

Table 10: Guide to scenarios

Scenario	Description
Central Case	This scenario adopts the central estimate for each variable in the economic assessment. It represents the most likely outcome.
Low demand	This scenario represents low demand driven by an increase in distributed energy resources. We have retained the other parameters at their central estimates, noting that the scenario is not driven by weak economic growth.
Weak economic growth	This scenario reflects weak economic growth, possibly due to the continuing impact of COVID-19. It has lower costs of delivering the option, lower demand and a lower discount rate
High demand	This scenario represents an economic rebound and continuing supply side issues. It is characterised by higher costs of delivering the option, higher demand and an upper bound discount rate.

The table below shows the net benefit for each scenario.

Table 11: Net benefit for each scenario ($M)

	Central case	Low demand	Weak economic growth	High demand
Option 1	0.0	0.0	0.0	0.0
Option 2	Not a credible option			
Option 3	Not a credible option			
Option 4	Not a credible option			
Option 5	17.10	15.79	32.07	6.94
Option 6	14.59	13.26	30.84	4.31
Option 7	13.04	11.75	30.43	2.79

Source: AusNet

On the basis of this scenario analysis, Option 5 is preferred to the other options, as it delivers a higher net economic benefit across each of the four scenarios

6.5. Preferred option

The results of the sensitivity testing confirm our finding that Option 5 is the preferred option, which is the replacement of all existing deteriorated outdoor 22kV bulk oil circuit breakers in C4 and C5 condition with three new indoor switchboards and associated secondary equipment within the new control building. In accordance with the RIT-D, this option is expected to maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM.

It should be noted that Option 5 is also the lowest cost credible option, as the other credible options require additional work to that described for Option 5. As such, any variation in the costs of delivering Option 5 following more detailed project scoping will not affect the ranking of the credible options or the selection of Option 5 as the preferred option in accordance with the RIT-D.

6.6. Capital and operating costs of the preferred option

The direct capital expenditure for the preferred option is $15.6 million, excluding management reserve and capitalised overheads, as shown below. The principal capital expenditure elements are:

- Design and internal labour, $2.95 million;
- Materials, $6.90 million;
- Plant and equipment, $0.31 million; and
- Contracts, $5.47 million.

The project costs will also include overheads and an allowance for risk.

The operating expenditure associated with this option will relate to the on-going inspection and maintenance of the assets. Our assessment is that a reasonable estimate of the annual operating expenditure is approximately 1.2% of the direct capital cost of the asset, which equates to approximately $190k per annum.

In relation to the timetable for completing these works, construction is expected to commence in late 2023 with commission readiness scheduled for June 2025.

7. Satisfaction of the RIT-D

In accordance with clause 5.17.4(j)(11)(iv) of the Rules, we certify that the proposed option satisfies the regulatory investment test for distribution. The table below shows how each of the Rules requirements have been met by the relevant sections of this report. As no submissions were received in response to the DPAR, 5.17.4(r)(1)(ii) is not applicable for this FPAR.

Table 12: Compliance with regulatory requirements

Requirement			Section
5.17.4(j) The draft project assessment report must include the following[10]:			
(1)		a description of the identified need for the investment;	Section 3.
(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 4.
(3)		if applicable, a summary of, and commentary on, the submissions on the non-network options report;	Not applicable.
(4)		a description of each credible option assessed;	Section 5.
(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;	Section 6.4.
(6)		a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure;	Sections 5 and 6.6.
(7)		a detailed description of the methodologies used in quantifying each class of cost and market benefit;	Section 6.2.
(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;	Section 6.1.
(9)		the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	Section 6.4.
(10)		the identification of the proposed preferred option;	Section 1.1 and 6.5.
(11)		for the proposed preferred option, the RIT-D proponent must provide:	
	(i)	details of the technical characteristics;	Appendix.
	(ii)	the estimated construction timetable and commissioning date (where relevant);	Section 6.6.
	(iii)	the indicative capital and operating cost (where relevant);	Section 6.6.
	(iv)	a statement and accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for distribution; and	Section 7, including this table.
	(v)	if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent;	Not applicable.

10 Although this provision refers to the draft project assessment report, it is applicable to this FPAR by virtue of clause 5.17.4(r)(1).

Requirement	Section
(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 1.3.

Appendix – Technical Characteristics

Scope of works

The high-level scope of work for the preferred solution includes:

Replacement of primary assets

- 66kV Switchyard
  - Replacement of 66kV VTs.
  - Decommission and remove the existing 66kV VT.
  - Replace RWTS-CYN line 66kV VT.
  - Decommission and remove the existing RWTS-CYN line 66kV VT.
  - Note that DD-0006495 is replacing the BRA line 66kV VT.
- Transformers
  - Retain 22kV Surge arresters on transformers and replace 66kV surge arresters.
  - Retire existing No1 25kVA station service transformer. It should be noted that the No1 SST is assumed to be the SST that is connected to the No1 22kV bus.
  - Retire existing No3 25kVA station service transformer. It should be noted that the No2 SST is assumed to be the SST connected to the No3 22kV bus.
  - Establish two new standard 315kVA (22/0.415kV) station service transformers.
- Install the following cables between:
  - No1 22kV Switchboard and No1 Transformer.
  - No2 22kV Switchboard and No2 Transformer.
  - No3 22kV Switchboard and No3 Transformer.
  - No1 22kV Switchboard and No2 22kV Switchboard.
  - No2 22kV Switchboard and No3 22kV Switchboard.
  - No3 22kV Switchboard and No1 22kV Switchboard.
  - No2 22kV Switchboard and No2 22kV Capacitor Bank.
  - No3 22kV Switchboard and No3 22kV Capacitor Bank.
  - No1 22kV Switchboard and No1 S/S Transformer.
  - No3 22kV Switchboard and No2 S/S Transformer.
- Possible temporary 22kV cable may be required. This will likely involve one 22kV cable between the existing 22kV AIS switchgear and the new 22kV switch room.
- 22kV Switchyard
  - Establish three new standard urban types 22kV modular switch rooms complete with a control room, which includes 22kV Bus VTs; 22kV Feeder CBs; 22kV Bus Tie CBs; 22kV Capacitor Bank CBs; Retire existing No.2 22kV 6MVar capacitor bank; and establish one new No.2 22kV 12MVar capacitor bank.
- Other works will include: earth grid and testing; civil and structural works; site establishment; footings and structures; earthworks/grading; storm water and drainage; and demolition.

Secondary works

Secondary works within BWR will include, but are not limited to, the design, procurement, installation/modification, testing and commissioning of the following:

- Existing control room, including works relating to new panels, modifications and decommissioning.
- New Modular 22KV switchroom, including three urban type 22kV switchrooms with switchboard cubicles.
- SCADA, including decommissioning the existing MD1000 RTU cubicles (Cubicle 34 & 22B) and establishing a new Cooper RTU.

In addition to the above works, costs will be incurred in relation to line works and communications.

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