Service constraints at Warragul (WGL) Zone Substation

Regulatory Investment Test for Distribution

Final Project Assessment Report

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1 Executive summary

AusNet Services is a regulated Victorian Distribution Network Service Provider (DNSP) that supplies electrical distribution services to more than 745,000 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 that we operate under, AusNet Services 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, which means that some 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 to address an identified need and considered, and the best option is selected.

This Final Project Assessment Report (FPAR) is the final stage of the RIT-D consultation process to address the existing and emerging service level constraints in the Warragul Zone Substation (WGL) supply area. It follows the publication of our non-network options report, which invited non-network proponents to engage on alternatives to our preferred network solution, and the publication of our Draft Project Assessment Report (DPAR) in February 2022. We did not receive any submissions in response to those reports.

This FPAR has been prepared by AusNet Services in accordance with the requirements of clause 5.17 of the National Electricity Rules (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.

With the exception of a relatively minor drafting changes, the content and findings presented in this FPAR are essentially unchanged from the DPAR.

1.1 Identified Need

WGL commenced operation as a 66/22kV transformation station in 1962. Three 10/12.5MVA transformers were installed in 1962. A fourth 10/13.5MVA transformer was added in 1997 as a replacement for an existing 5/6.5MVA transformer, however this transformer was manufactured in 1965. A fifth 20/33MVA transformer was added in 2011. The 66kV switchyard was constructed in the 1960s, with the exception of an additional 66kV CB added in 2011 when the fifth transformer was installed. The 22kV switchyard was replaced by an indoor switchboard in 1997.

The physical and electrical condition of some assets has deteriorated, and they are now presenting an increasing failure risk.

The station has a 66kV ring bus arrangement, but is partially switched with the four 1960's vintage transformers switched as a single group, and a normally open isolator in place of a 66kV circuit breaker between the two 66kV line entries from Yallourn Power Station (YPS).

The key service constraints at WGL are:

- Security of supply risk presented by the switching of four of the transformers in a single group;
- Security of supply risks presented by increased likelihood of asset failure due to the deteriorating condition of the assets;

- Health and safety risks presented by a possible explosive failure of bushings on a number of the assets;
- Plant collateral damage risks presented by a possible explosive failure of bushings on 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; and
- Health and safety risks presented by cement sheets or electrical switch boards containing asbestos in the main building and switchyard.

1.2 Preferred option

This FPAR considered the following potentially credible options that may be capable of meeting the identified need:

1. Business as Usual (counterfactual)
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 four transformers with two transformers and replace capacitor bank
6. Replace four transformers with two transformers, replace the existing capacitor bank and install two new 66kV circuit breakers
7. Replace four transformers with four transformers and replace capacitor bank.

Following a detailed assessment of these options in accordance with the RIT-D, Option 6 has been identified as the preferred option.

1.3 Contact details

Any questions regarding this report should be directed to:

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2 Background

2.1 Existing network

WGL is located approximately 100km south east of Melbourne and is the main source of supply for the suburbs of Warragul, Drouin, Longwarry, Bunyip, Darnum, Noojee and surrounding areas.

WGL supplies approximately 23,300 AusNet Services' customers. The load at WGL includes mostly residential load with some farming, commercial and industrial loads. The Warragul Zone Substation is in West Gippsland at an elevation of 143m above sea level. WGL has summer average maximum temperatures of 24°C, winter average minimum temperatures of 6°C with extreme temperatures reaching 44°C in summer and -5°C in winter. The average annual rainfall is 837mm in this area.

WGL is supplied at 66kV via two 66kV circuits that originate from Morwell Terminal Station (MWTS). These lines also serve YPS and Moe Zone Substations.

The location of WGL within the AusNet Services distribution network is as shown in Figure 1.

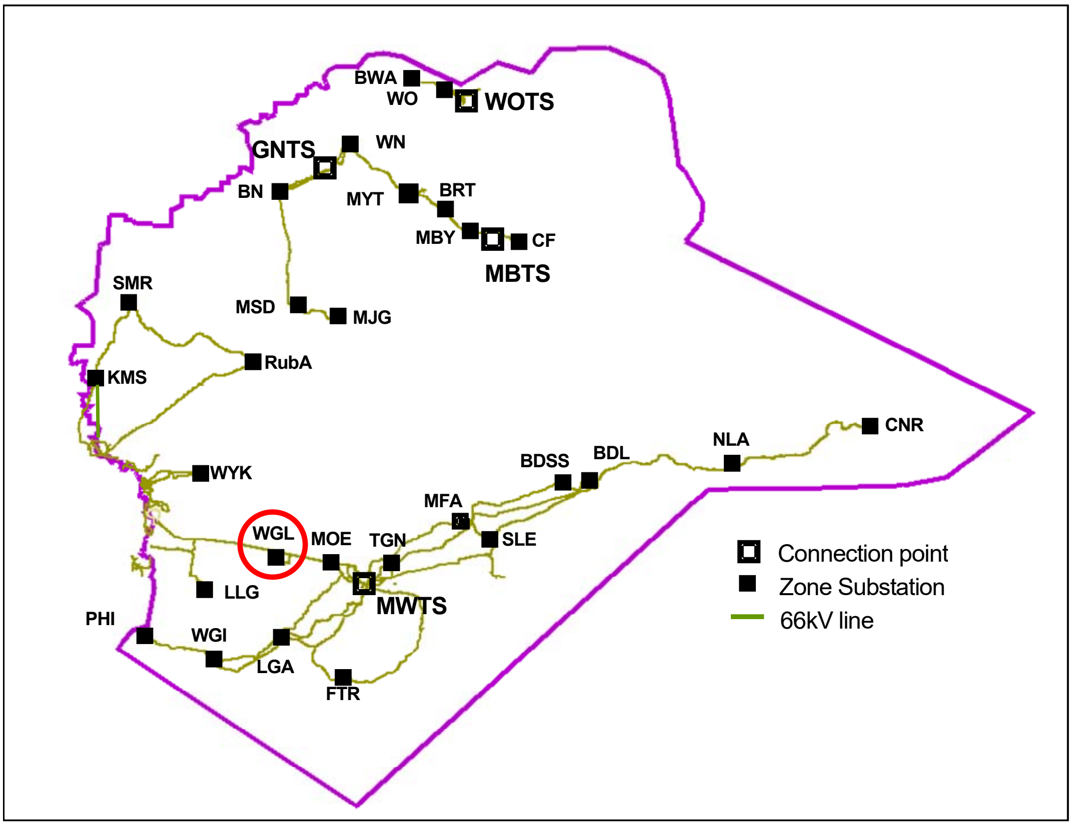

Figure 1: WGL location within AusNet Services distribution network

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

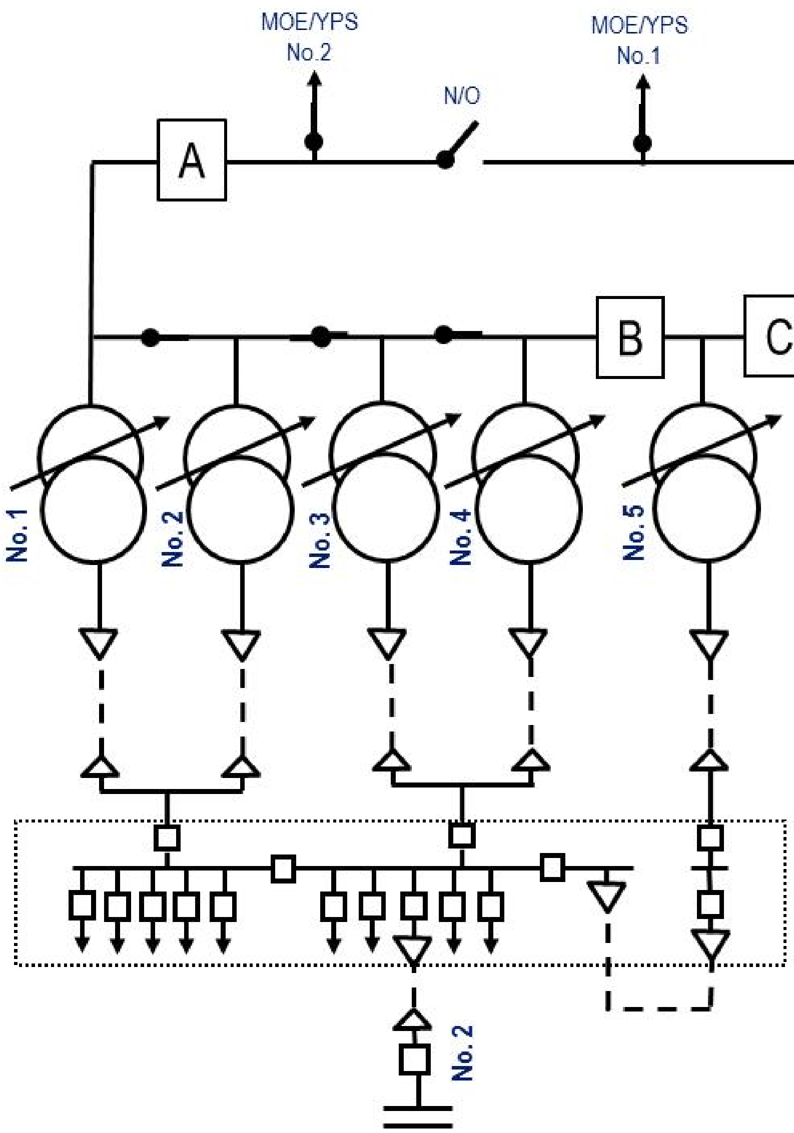

Figure 2: WGL Single Line Diagram

2.2 Customer Composition

WGL has nine 22kV feeders supplying AusNet Services' customers. Table 1 provides details of the 22kV supply feeders.

Table 1: WGL feeder information

Feeder	Feeder Length (km)	Feeder description	Number of Customers	Type of Customers
WGL11	58	Summer peaking, short rural feeder	3,808	84% residential 5% commercial 1% industrial 10% farming

Feeder	Feeder Length (km)	Feeder description	Number of Customers	Type of Customers
WGL12	325	Summer peaking, long rural feeder	3,501	75% residential 5% commercial 1% industrial 19% farming
WGL13	150	Summer peaking, short rural feeder	3,899	90% residential 7% commercial 3% farming
WGL14	8	Summer peaking, urban feeder	1	100% commercial
WGL15	116	Summer peaking, short rural feeder	2,809	73% residential 18% commercial 1% industrial 8% farming
WGL21	227	Summer peaking, long rural feeder	4,813	88% residential 3% commercial 1% industrial 8% farming
WGL22	10	Summer peaking, urban feeder	1	100% commercial
WGL23	167	Summer peaking, short rural feeder	1,359	50% residential 17% commercial 3% industrial 30% farming
WGL24	423	Summer peaking, long rural feeder	3,116	64% residential 6% commercial 1% industrial 29% farming

The medium voltage feeders interconnect with medium voltage feeders from Pakenham, Moe and Leongatha Zone Substations but the distance to these stations and loading on these feeders means that only 3.4MVA of load is able to be transferred to these stations via 22kV feeders.

2.3 Zone Substation Equipment

2.3.1 Primary Equipment

WGL includes an air-insulated 66kV switchyard with eight 66kV buses separated by either bus-tie circuit breakers or isolators connected to two incoming 66kV lines from Morwell Terminal Station (MWTS) via YPS and MOE. CB “A” and CB “B” are minimum oil CBs rated at condition C5.

There are two 22kV indoor switchboards. Bus 1 is connected to a bank of two 10/12.5MVA transformers via a single 22kV transformer CB. Bus 2 is connected to a bank of two transformers (1 x 10/12.5MVA and 1 x 10/13.5MVA) via a single 22kV transformer CB, and the newer 20/33MVA transformer via the Bus 2-3 bus tie CB. Nine 22kV feeders and one 6 MVAR and one 12 MVAR capacitor banks are connected to these 22kV busbars.

Transformation comprises one 10/13.5MVA 66/22kV transformer located at position No.1 manufactured by Wilson at condition C4, three 10/12.5MVA 66/22kV transformers located in the No.2, No.3 and No.4 positions manufactured by Asea rated at C4 and installed in the 1960s, and one 20/33MVA 66/22kV transformer located in the No.5 position manufactured by Shihlin rated at C1 installed in 2011.

2.3.2 Secondary Equipment

The two incoming 66kV lines are YPS/MOE No.1 and No.2 Lines. YPS/MOE No.1 Line is protected by an ABB LZ31 distance protection of obsolete analogue electronic type as X protection and a GE L90 numerical current differential relay as Y protection. The former is being replaced with a modern numerical type current differential protection. YPS/MOE No.2 Line has X and Y protection that are both modern numerical relays.

The existing 66kV bus protection is an obsolete ABB RAKZB analogue electronic relay. This will be replaced by numerical X (SEL487) and Y (Siemens 7UT87) relays in a protection upgrade project.

Auto Reclose (ARC) of 66kV CBs is presently handled by obsolete Group 2873 relays. Built in ARC functions in numerical line protection relays will replace existing ARC relays when the protection upgrade project is completed.

Duplicated X and Y CB failure protection are provided for 66kV CBs using numerical SEL551 and early generation digital 2C63 relays.

Protection for Transformers No.1, No.2, No.3 and No.4 are not duplicated. Transformers No.1, No.2 and No.4 are protected by first generation digital type relays KBCH120. Transformer No.3 is protected by electromechanical type D21SE2 relays. These relays will be replaced with duplicated X and Y biased differential protection of numerical type in the protection upgrade project. Modern numerical type biased differential relays are used for X and Y protection of Transformer No.5.

All transformers have numerical voltage regulating relays (VRR) using Reyrolle Microtapp.

The 22kV bus protection consists of high impedance bus protection using ABB RADHA relays and bus distance protection using GE – D30 relays. The former will be replaced with numerical type ABB REF630 relays in the protection upgrade project.

Numerical type relays ABB REF630 and GE F35 are used for 22kV master earth fault (MEF) and backup earth fault (BUEF) protection respectively.

All 22kV feeders have numerical feeder protection using GE F650 relays.

The 22kV capacitor bank protection has overcurrent, earth fault and voltage balance schemes using a GE F650 relay. The station has duplicated 240V AC systems and battery chargers that supply a 120V DC system for the protection relays and trip coils.

3 Identified Need

WGL commenced operation as a 66/22kV transformation station in 1962. Three 10/12.5MVA transformers were installed in 1962. A fourth 10/13.5MVA transformer was added in 1997 as a replacement for an existing 5/6.5MVA transformer, however this transformer was manufactured in 1965. A fifth 20/33MVA transformer was added in 2011. The 66kV switchyard is practically as it was constructed in the 1960s, with the exception of an additional 66kV CB added in 2011 when the fifth transformer was installed. The 22kV switchyard was replaced by an indoor switchboard in 1997.

The physical and electrical condition of these assets has deteriorated, and they are now presenting an increasing failure risk.

The station has a 66kV ring bus arrangement, but is partially switched with the four 1960's vintage transformers switched as a single group, and a normally open isolator in place of a 66kV circuit breaker between the two 66kV line entries from YPS.

The key service constraints at WGL are:

- Security of supply risk presented by the switching of four of the transformers in a single group;
- Security of supply risks presented by increased likelihood of asset failure due to the deteriorating condition of the assets;
- Health and safety risks presented by a possible explosive failure of bushings on a number of the assets;
- Plant collateral damage risks presented by a possible explosive failure of bushings on 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; and
- Health and safety risks presented by cement sheets or electrical switch boards containing asbestos in the main building and switchyard.

4 Assumptions underpinning the identified need

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

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 Services to only propose capital expenditure required in order 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 Services 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 3.1 of the Electricity Distribution Code requires AusNet Services to:

(b) 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;*
>
> (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 5.2 of the Electricity Distribution Code, AusNet Services:

> *must use best endeavours to meet targets required by the Price Determination and targets published under clause 5.1 and otherwise meet reasonable customer expectations of reliability of supply.*

4.2 Asset Condition

AMS 10-13 Condition Monitoring describes AusNet Services' 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. Table 2 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 WGL 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 WGL is provided in Table 3 and discussed in the following sections.

Table 3: WGL Asset Condition Summary

Asset Type	Number of assets by Condition Score				
	C1	C2	C3	C4	C5
66kV Circuit Breakers	1				2
66kV Current Transformers			6		
66kV Voltage Transformers					7
66/22kV Power Transformers	1			4	
22kV Circuit Breakers	3	15			
22kV Current Transformers	2	16	6	4	
22kV Voltage Transformers	1	5			

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

WGL is a summer peaking station and the peak electrical demand reached 64.9MVA in the summer of 2019/20. The recorded peak demand in winter 2021 was 53.5MVA. The demand at WGL is forecast to increase at a growth rate of approximately 2.3% per annum.

Error! Reference source not found. shows the forecast maximum demand and supply capacities (cyclic ratings) for WGL.

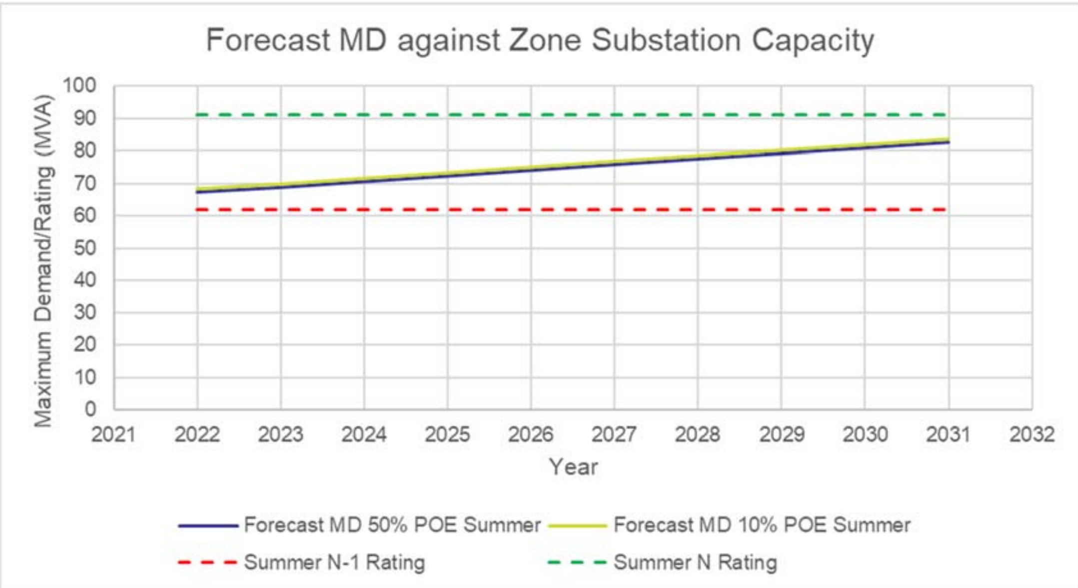

Figure 3: WGL Forecast Maximum Demand against Zone Substation Capacity

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 between:

- 1 October 2019 and 31 March 2020 for the summer 50% probability of exceedance (POE) curves;
- 1 April 2020 and 30 September 2020 for the winter 50% POE curves;
- 1 October 2019 and 31 March 2020 for the summer 10% POE curves; and
- 1 April 2020 and 30 September 2020 for the winter 10% POE curves.

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 WGL is presented in

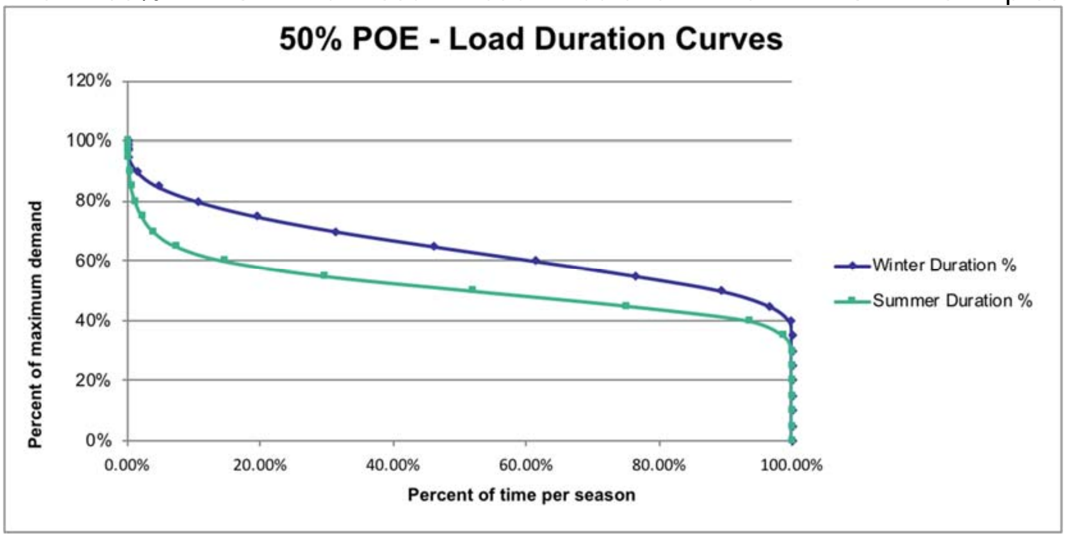

Figure 4, and the 10% POE unitised load duration for WGL is presented in Figure 5.

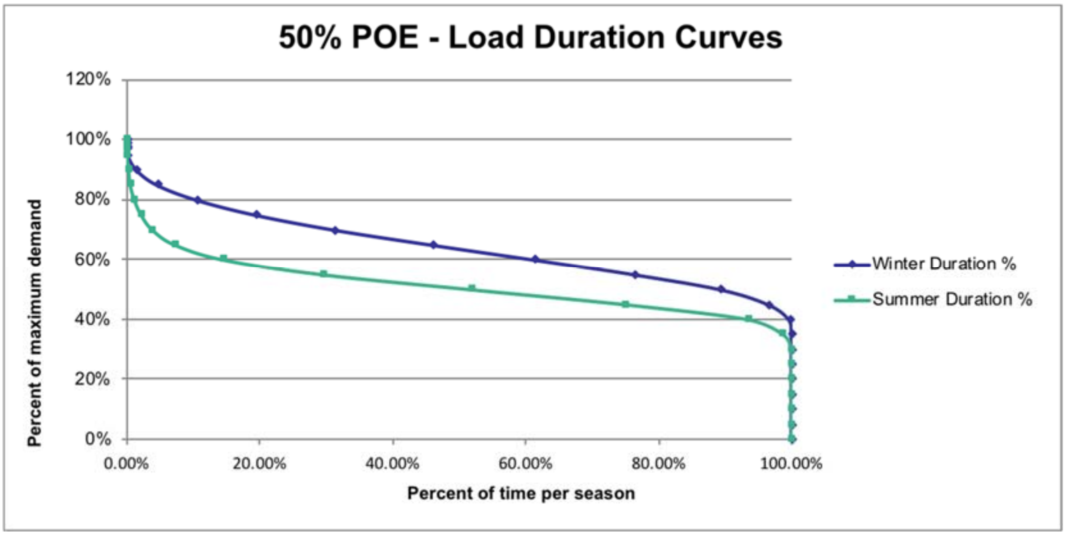

Figure 4: WGL 50% Load Duration Curves

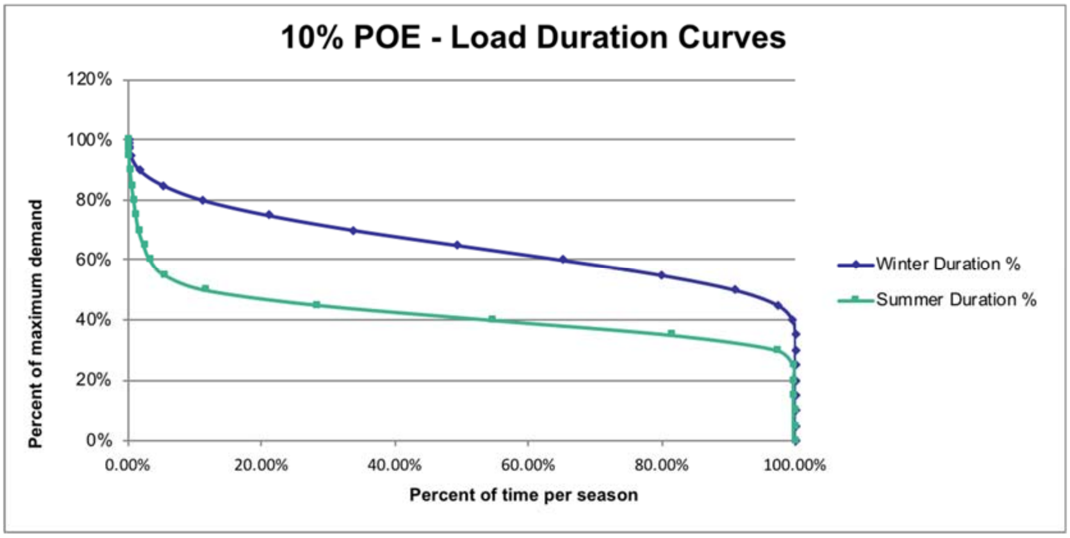

Figure 5: WGL 10% POE Load Duration Curves

4.5 Feeder Circuit Supply Capacity

A new feeder is planned for the WGL area within the next two years due to rapid load growth in the Drouin, Longwarry and Bunyip areas.

4.6 Load Transfer Capability

The Distribution Annual Planning Report (DAPR) provides the load transfer capability (in MW) of the feeder interconnections between WGL and its neighbouring Zone Substations. Our forecast load transfer capability for WGL is presented in Table 4.

Table 4: WGL Load Transfer Capability

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Load Transfer Capability (MW)	3.2	3.1	3.1	3	2.9	2.9	2.8	2.7	2.7	2.6

4.7 Station Configuration Supply Risk

Failure of some 66kV and 22kV equipment will result in supply outages to customers as backup circuit breakers operate to isolate the failed equipment.

This would be for an estimated duration of two hours, which is the typical time it takes operators to travel to site and manually reconfigure circuits to isolate the failed equipment and sequentially restore supply to as many customers as possible.

Table 5 lists the estimated bus outage consequence factors for each major type of equipment based on the substation layout.

Table 5: WGL Bus Outage Consequence Factors

Equipment	Estimated Bus Outage Consequence
Transformer	0%
22kV circuit breaker	47%

Equipment	Estimated Bus Outage Consequence
66kV circuit breaker	33%
22kV current transformer	47%
66kV current transformer	33%
22kV voltage transformer	17%
66kV voltage transformer	0%

5 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 risks at WGL:

1. Business as Usual (counterfactual)
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 four transformers with two transformers and replace capacitor bank
6. Replace four transformers with two transformers, replace the existing capacitor bank and install two new 66kV circuit breakers
7. Replace four transformers with four transformers and replace capacitor bank

Each of the network options to address the identified need would need to be delivered during the 2021-25 EDPR period.

5.1 Option 1: Business as Usual

The Business as Usual (counterfactual) option 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 provides a basis for comparing potential options.

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.

The estimated capital cost for this option is $100k, for associated decommission works.

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. The cost of obtaining network support will be the principal direct cost associated with this option, with capital expenditure of approximately $130k for the associated decommissioning works and setting up a network support agreement.

The purpose of the non-network options report was to test with non-network proponents whether this option is feasible and to better understand the likely costs of procuring network support. No submissions were received from non-network proponents and, therefore, this option is no longer considered to be credible. This option is not considered further in this FPAR.

5.4 Option 4: Use network support to defer retirement and replacement

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

As noted in relation to Option 3, this option will involve relatively modest direct costs to decommission assets and set up a network support agreement. The principal costs of this option is the cost of procuring network support. As we received no responses to the non-network options report, this option is no longer considered credible and is not considered further in this FPAR.

5.5 Option 5: Replace four transformers with two transformers and replace capacitor bank

In this option, the three 10/12.5MVA and one 10/13.5MVA transformers are replaced with two 20/33MVA transformers. The capacitor bank is also replaced.

This option has an estimated capital cost of $12.64 million.

5.6 Option 6: Replace four transformers with two transformers, replace the existing capacitor bank and install two new 66kV circuit breakers

In this option, the three 10/12.5MVA and one 10/13.5MVA transformers are replaced with two 20/33MVA transformers. Two new 66kV circuit breakers are installed and the capacitor bank is replaced. The existing C5 66kV circuit breakers will be replaced under a separate project.

This option has an estimated capital cost of $16.6 million.

5.7 Option 7: Replace four transformers with four transformers and replace capacitor bank

In this option, the three 10/12.5MVA and one 10/13.5MVA transformers are replaced with four 10/15MVA transformers. The capacitor bank is also replaced.

This option has an estimated capital cost of $17.64 million.

6 Economic assessment of the credible options

6.1 Market benefits

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 NER. 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 at WGL.

Table 6: 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 Services 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 in 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 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'). In order 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.

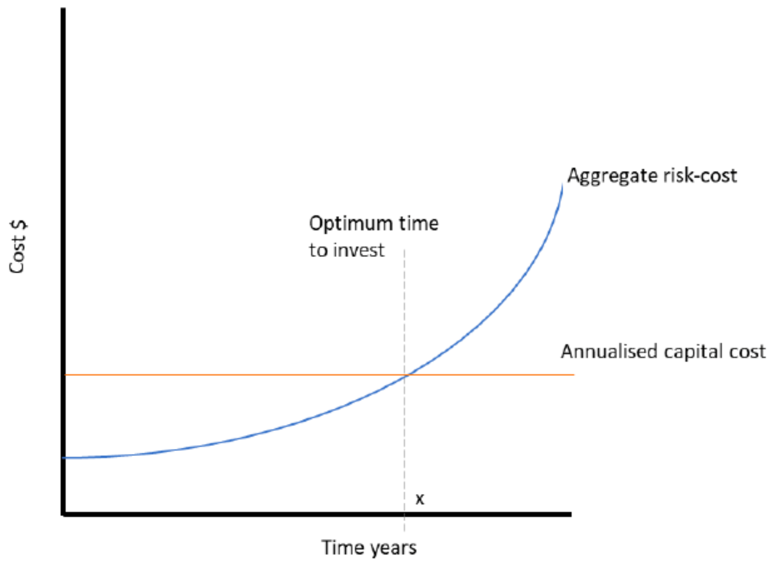

Figure 6: Increasing risk-cost over time and optimal project timing[1]

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. As a consequence, the RIT-D analysis must be conducted in the face of uncertainty.

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.[2] The relationship between sensitivity analysis and scenarios is best explained by the AER's practice note:[3]

> *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.*

1 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.

2 AER, Application guidelines, Regulatory investment test for distribution, December 2018, page 42.

3 AER, Asset replacement planning, January 2019, page 36.

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 draft 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 particular circumstances described in this report relating to the identified need and the credible options.

6.3 Key variables and assumptions

Table 7 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 is provided in section 6.4.

Table 7: Key variables and assumptions ($M)

Variable / assumption	Lower bound	Central estimate	Upper bound
Demand forecasts	5% reduction in central estimate of annual growth rate	Average annual growth rate of 2.3%	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 $38,217 per MWh[4]	25% increase in central estimate
Safety cost	Central Estimate	Value of statistical life of $4.5 million[5]	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
Real discount rate per annum[6]	2.0%	5.5%	7.5%

4 Calculated using the latest VCR estimates for each sector, refer to model 'Inputs – Global' tab.

5 Best Practice Regulation Guidance Note Value of statistical life, December 2014, escalated, refer to model 'Inputs – Global' tab.

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

Variable / assumption	Lower bound	Central estimate	Upper bound
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: WGL_V6.0_Economic_Model-Master_Template_16-01-22

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 8 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 it is considered in our PV analysis which is reported later in this section.

Table 8: 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 does not provide a net benefit in any year to 2031 and is not credible.									
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	0.0	0.0	0.0	0.0	0.1	0.4	0.8	1.3	2.1	3.4
Option 6	0.0	0.0	0.0	0.1	0.4	0.7	1.1	1.7	2.5	3.8

Option 7	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.9	1.7	2.9

Source: WGL_V6.0_Economic_Model-Master_Template_16-01-22

Based on the table set out above, Option 2 is not credible it does not provide a net benefit in any year to 2031. On that basis, this option alongside Options 3 and 4 are not considered further in this RIT-D assessment. Of the remaining options, Option 6 delivers a net benefit sooner than the competing options and 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 values for each option over its life, using our central estimates, based on the optimal timing for each option.

Table 9: Net economic benefit ($M)

	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	$39.49	$9.88	$29.61
Option 6	$45.91	$11.51	$34.40
Option 7	$38.11	$12.84	$25.27

Source: WGL_V6.0_Economic_Model-Master_Template_16-01-22

The present value analysis shown in Table 9 shows that Option 6 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 is presented below.

Table 10: 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	66.8	8.8	56.1	14.0	28.2	31.1	29.8	29.6
Option 6	75.7	10.8	61.3	18.4	32.7	36.2	35.4	34.3
Option 7	61.5	5.5	50.8	10.4	23.5	27.2	25.5	25.2

Source: WGL_V6.0_Economic_Model-Master_Template_16-01-22

The sensitivity analysis shows that Option 6 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 range of different parameter inputs. To test our results further, we have adopted four scenarios, as set out below.

Table 11: 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 12 below provides a brief description of each scenario.

Table 12: 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 as a result of 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.

Table 13: 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	29.6	14.0	19.5	43.7
Option 6	34.4	18.4	25.3	47.7
Option 7	25.3	10.4	15.9	38.5

Source: WGL_V6.0_Economic_Model-Master_Template_16-01-22

On the basis of this scenario analysis, Option 6 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 our cost benefit analysis is that Option 6 is the preferred option, which involves the following works:

- the three 10/12.5MVA and one 10/13.5MVA transformers are replaced with two 20/33MVA transformers; and
- two new 66kV circuit breakers are installed and the capacitor bank is replaced.

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.

In relation to the optimal timing of the preferred option, our modelling indicates that the project should be delivered by 2025 on the basis of our central estimates. Further details on the sequencing of works and cost estimates are provided in the Appendix.

6.6 Capital and operating costs of the preferred option

The direct capital expenditure for the preferred option is $16.6 million, excluding management reserve and capitalised overheads, as shown in the table below.

Table 14: Summary of capital expenditure requirements, $'000, $2021

	FY22	FY23	FY24	**FY25**	Total
Direct capital expenditure	240.3	2,474.7	10,142.0	3,734.7	**16,591.6**

Source: AusNet Services

Note: Excludes overheads, management reserve, written down value of assets retired/sold.

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 $200k per annum.

In relation to the timetable for completing these works, we expect construction to commence following design completion by 30 April 2022, with commission readiness completed by 30 September 2024. The project is expected to reach completion by 30 December 2024.

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 15: Compliance with regulatory requirements

Requirement	Section
5.17.4(j) The draft project assessment report must include the following[7]:	
(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;	No submissions were received.
(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, Table 9 and 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 6.4.
(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.

[7] 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
(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.
(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 scope of works for this project are summarised as follows:

1. Replace four aged 10/13MVA 66/22kV transformers with two (2-off) new 20/33MVA transformers.
2. Install two (2-off) new 66kV RDB disconnectors for the new transformers.
3. Install two (2-off) new cageless neutral isolator assembly with neutral CTs for the new transformers.
4. Establish a full 66kV ring bus:
    a) Install a new 66kV CB between YPS/MOE No1 and No2 Lines (designated "CB D").
    b) Install a new 66kV CB between the new No1 Transformer and No2 Transformer (designated "CB E").
    c) Install fifteen off (15-off) 66kV single phase underslung isolators associated with the 66kV CBs.
    d) Replace other aged and poor condition 66kV assets:
        i) Two off (2-off) 66kV CBs (CB A and CB B).
        ii) Three off (3-off) 66kV single phase post VTs.
    e) Replace 66kV strung bus and establish rigid bus system.
5. Replace the aged 22kV Capacitor Bank with a new 12MVAr (4x3MVAr) metal enclosed Capacitor Bank.
6. Install a new modular control building.
7. Install two (2-off) modular battery enclosures to replace existing station DC supplies.
8. Install and removal of the temporary 66kV connection.
9. Install extension of fences and access roads.
10. Perform earth grid study including earth grid upgrade if required. Install all required primary connections and associated earthing grid connections.
11. Associated civil and structural works.
12. Associated secondary protection, control and communications works.

Technical assumptions

The following technical assumptions and clarifications are made:

1. The existing control building is earmarked for future retirement and demolition. This project assumes the following philosophy to ensure economical long-term progression towards this goal:
    a. All new equipment shall be installed as independently of this building as practical.
    b. No equipment from within the existing control room will be proactively replaced (excluding schemes and equipment directly affected by primary asset replacements).

2. Loading at WGL is relatively high compared to the station's N rating and cannot sustain a prolonged outage on all four banked transformers simultaneously. It is assumed (alongside suitable scheduling, such as shoulder seasons) that:
    a. Once the No.1 transformer is replaced, it is understood that the existing No.2-4 transformers can be taken out of service in stages to facilitate the 66kV ring rebuild and the 2nd 20/33MVA transformer installation.
    b. During this period, two 20/33MVA 66/22kV Transformers (No.1 and No. 5) may carry the station load for an extended duration (45-90 days) while the 2nd 20/33MVA transformer is being installed.
3. Secondary equipment replaced as part of the in-flight project DD-0002925 will be retained only where it is the most technically suitable solution. Where a protection panel does not align with present standards for protection it shall be replaced to minimise staging and commissioning complexity for the 66kV bus.
4. Delivery vehicles for transformers are able to access the access road to the west of the site, and the adjoining yard owned by Ausnet Services (leased to Downer) can be accessed by the project if required.
5. Transformers can be installed via 'jack & skate' into position from existing roadway.
6. The acquisition of land adjacent to the WGL site is required to support the requirements of this Business Case and will be undertaken prior to completion of Design Phase.

Asset replacement and augmentation works

The figure below provides an overview of the planned works.