Service constraints at Maffra 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 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 are 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 Maffra Zone Substation (MFA) supply area. This FPAR follows the publication of the Draft Project Assessment Report (DPAR) in March 2022. We also published 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 are capable of addressing the identified need at MFA. We did not receive any submissions in response to those reports.

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. The RIT-D analysis concludes that Option 5 is the preferred option, which is the replacement of five existing 66kV circuit breakers with air insulated switchgear.

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

MFA commenced operation in 1960 and the 66kV switchyard is practically unchanged. Our assessment is that the physical and electrical condition of a number of assets at MFA have deteriorated and are now presenting an increasing failure risk. The primary issues at MFA arise from the following asset-related risks:

a) Health and safety risks presented by a possible explosive failure of bushings on a number of the assets;
b) Plant collateral damage risks presented by a possible explosive failure of bushings on a number of the assets;
c) Environmental risks associated with insulating oil spill or fire;
d) Reactive asset replacement risks presented by the increasing likelihood of asset failure due to the deteriorating condition of the assets; and
e) Health and safety risks presented by cement sheets or electrical switch boards containing asbestos in the control building, storeroom and toilet.

Our planning report for MFA also highlighted the security of supply risks that arise from the station configuration, as all three transformers are switched as a single group. 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.

1.2 Options considered and preferred option

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

1. Do Nothing (counterfactual)
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 66kV circuit breakers
6. Replace No.3 transformer and 66kV circuit breakers
7. Replace and relocate No.2 transformer and 66kV circuit breakers
8. Replace two transformers and 66kV circuit breakers

Options 2, 3 and 4 were found not to be credible. Of the remaining options, Option 5 was found to maximise the present value of net economic benefit in accordance with the RIT-D. This option also has the lowest capital cost of the credible options.

1.3 Contact details

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2 Background

2.1 Existing network

MFA is located approximately 220 km east of Melbourne (VicRoads map reference 694 C-7) and is the main source of supply for Maffra, Nambrok, Heyfield, Licola, Boisdale, Briagolong, Stratford and surrounding areas. MFA is located at an elevation of 30 m above sea level.

MFA has a summer average maximum temperature of 25°C and a winter average minimum temperature of 4°C. Extreme temperatures reach 44°C in summer and -6°C in winter. The mean rainfall varies from 41 mm to 63 mm per month within a year.

MFA supplies approximately 8,350 customers. The load at MFA includes town and rural based residential, with some town based commercial, industrial and farming. The largest customer supplied from MFA is a milk processing plant owned by Saputo (Dairy Australia). This plant is a major employer in the community and performs an essential role for the region's dairy producers. The electrical supply to the plant is critical to compliant operation of sensitive milk processing equipment.

A special switching arrangement at MFA is employed by opening the No.1-2 22kV bus tie. This configuration with a single small feeder (MFA 14) effectively provides a 66kV point of common coupling to Saputo and provides protection to the plant from power variations that result from the day to day operation of the remaining five feeders on the No.2 and No.3 22kV buses.

As shown in Figure 1, MFA is supplied via a 66kV network that connects between:

- Morwell Terminal Station (MWTS);
- Bairnsdale Switching Station (BDSS);
- Traralgon Zone Substation (TGN); and
- Sale Zone Substation (SLE).

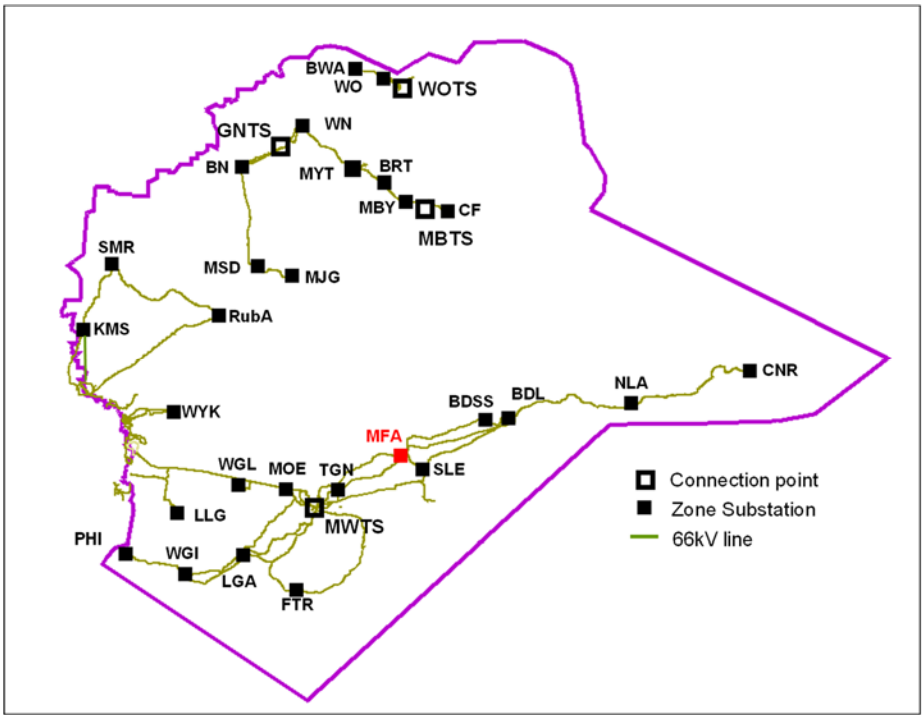

Figure 1: MFA location within AusNet Services subtransmission network

The configuration of primary electrical circuits within MFA is as shown in the following single line diagram (**Figure 2**), where the 66kV switchyard is shown on the right, and the 22kV switchgear is shown on the left.

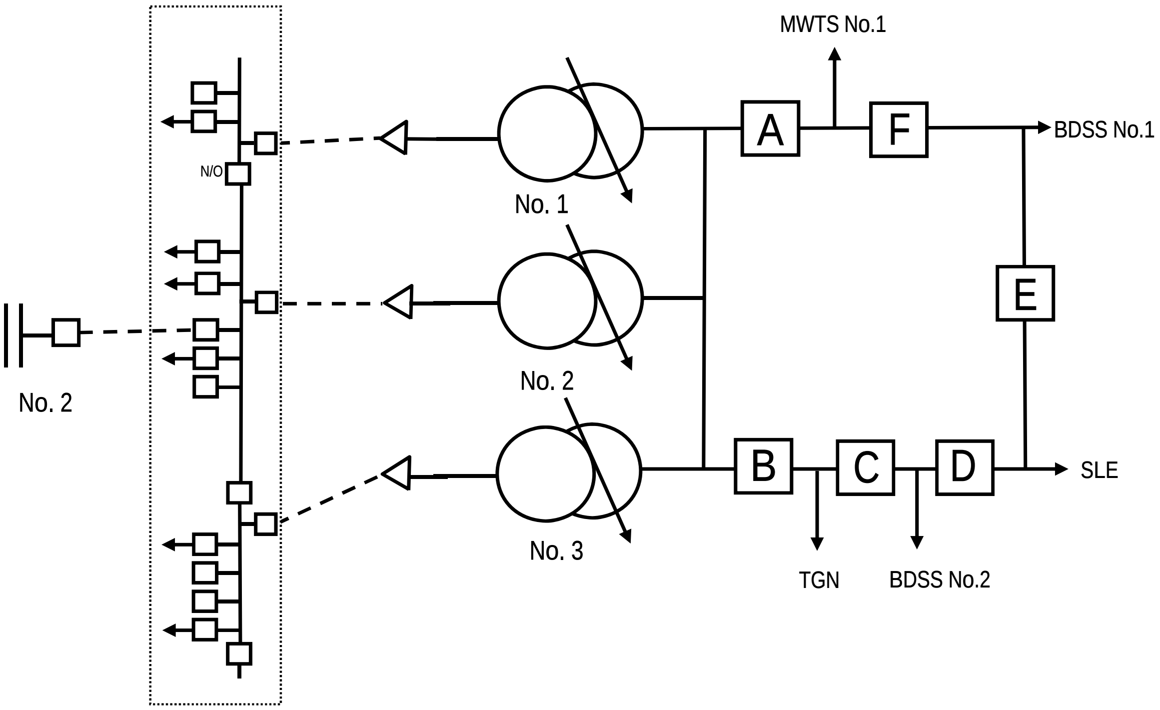

Figure 2: Single Line Diagram of MFA

2.2 Customer Composition

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

Table 1: MFA feeder information

Feeder	Feeder Length (km)	Feeder description	Number of Customers	Type of Customers
MFA14	0.9	Summer peaking, urban feeder	31 (Including Saputo)	30% residential 55% commercial 15% industrial
MFA21	434	Summer peaking, long rural feeder	2,417	55% residential 8% commercial 2% industrial 35% farming
MFA22	319	Summer peaking, long rural feeder	1,648	39% residential 10% commercial 2% industrial 49% farming
MFA23	128	Summer peaking, short rural feeder	495	39% residential 12% commercial 3% industrial 46% farming

Feeder	Feeder Length (km)	Feeder description	Number of Customers	Type of Customers
MFA31	26	Summer peaking, short rural feeder	2,157	93% residential 5% commercial 1% industrial 1% farming
MFA34	185	Summer peaking, short rural feeder	1,523	59% residential 11% commercial 2% industrial 28% farming

The 22kV feeders interconnect with 22kV feeders from Sale, Traralgon and Bairnsdale zone substations, but the long distances to these stations means that only 6.5MVA of load is able to be transferred away from MFA to these adjacent zone stations via the 22kV feeders.

2.3 Zone Substation Equipment

2.3.1 Primary Equipment

MFA includes an air insulated 66kV switchyard with eight busbars configured as a 66kV ring with six 66kV circuit breakers switching one line from Morwell Terminal Station (MWTS), one line from Traralgon Zone Substation (TGN), one line from Sale Zone Substation (SLE) and two lines from Bairnsdale Switching Station (BDSS).

There are three 22kV buses in an indoor switchroom supplying six 22kV feeders and one 12MVAr capacitor bank consisting of four 3MVAr modules.

The 66kV circuits are switched by six minimum oil 66kV circuit breakers. Three units were installed in 1982, two units in 1963 and one unit was installed in 1967.

The 22kV indoor switchboard currently has seventeen 22kV circuit breakers, comprising ten feeder circuit breakers (including four spares), two bus-tie circuit breakers, three transformer circuit breakers, one circuit breaker that protects the capacitor bank and one extra circuit breaker allowed for the future capacitor bank. All 22kV circuit breakers were installed in 1998.

Transformation comprises three 10MVA 66/22kV transformers that are switched as a single group. The No.2 and No.3 transformers were originally installed in 1960 when the station was established. The No.1 transformer was added in 1998.

2.3.2 Secondary Equipment

The 66kV line circuit breakers have circuit breaker failure and auto reclose schemes using Group relays. The 22kV feeder circuit breakers have overcurrent, earth fault and sensitive earth fault using modern numeric relays. MFA’s 22kV capacitor bank protection has neutral balance and capacitor control device functions using modern numeric relays.

The transformers have differential protection, voltage regulating and restrictive earth fault protection using old digital relays. MFA’s bus protection has overcurrent and distance protection using old digital relays.

2.4 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 MFA 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 MFA is provided in Table 3 and discussed in the following sections.

Table 3: MFA Asset Condition Summary

Asset Type	Number of assets by Condition Score				
	C1	C2	C3	C4	C5
66kV Circuit Breakers			1	2	3
66kV Current Transformers				18	
66kV Voltage Transformers				3	15
66/22kV Power Transformers		1		2	
22kV Circuit Breakers	12	5		1	
22kV Current Transformers		20	2		
22kV Voltage Transformers		7			

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

2.5 Zone Substation Supply Capacity

MFA is a summer peaking station and the peak electrical demand reached 36.1MVA in the summer of 2017/18. The recorded peak demand during the winter of 2018 was 26.2MVA.

The demand at MFA is forecast to increase slowly at a growth rate of around 1% per annum. Figure 3 shows the forecast maximum demand and supply capacities (cyclic ratings) for MFA.

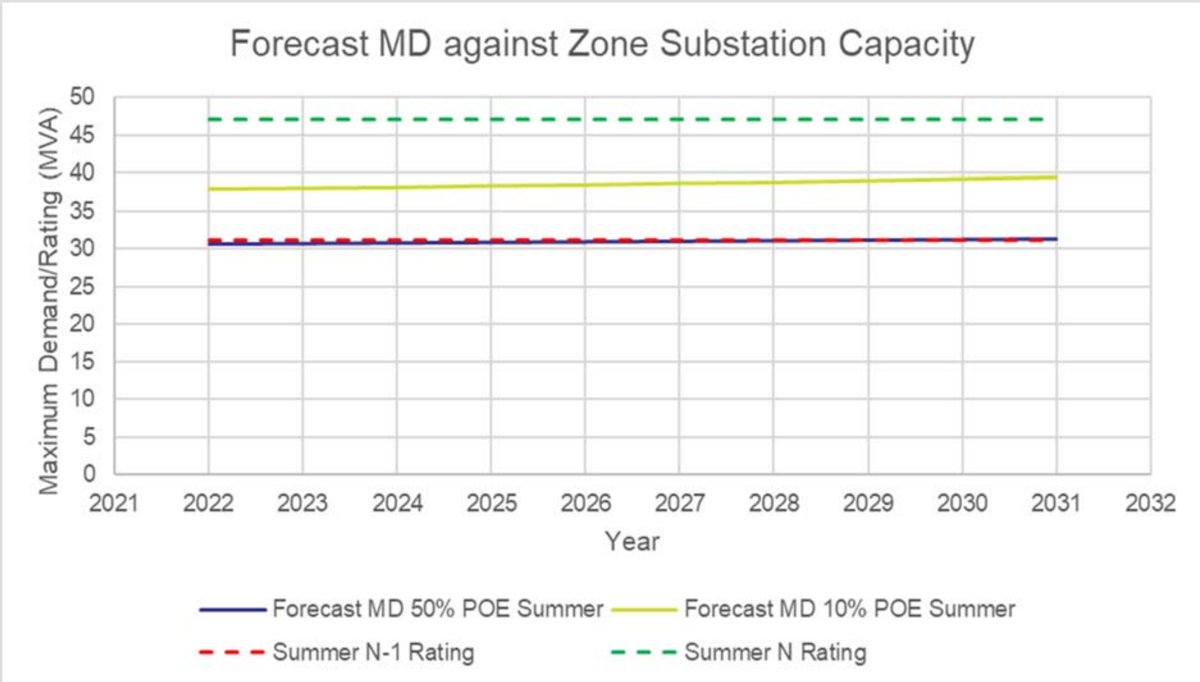

Figure 3: MFA Forecast Maximum Demand against Zone Substation Capacity

2.6 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 MFA zone substation is presented in Figure 4.

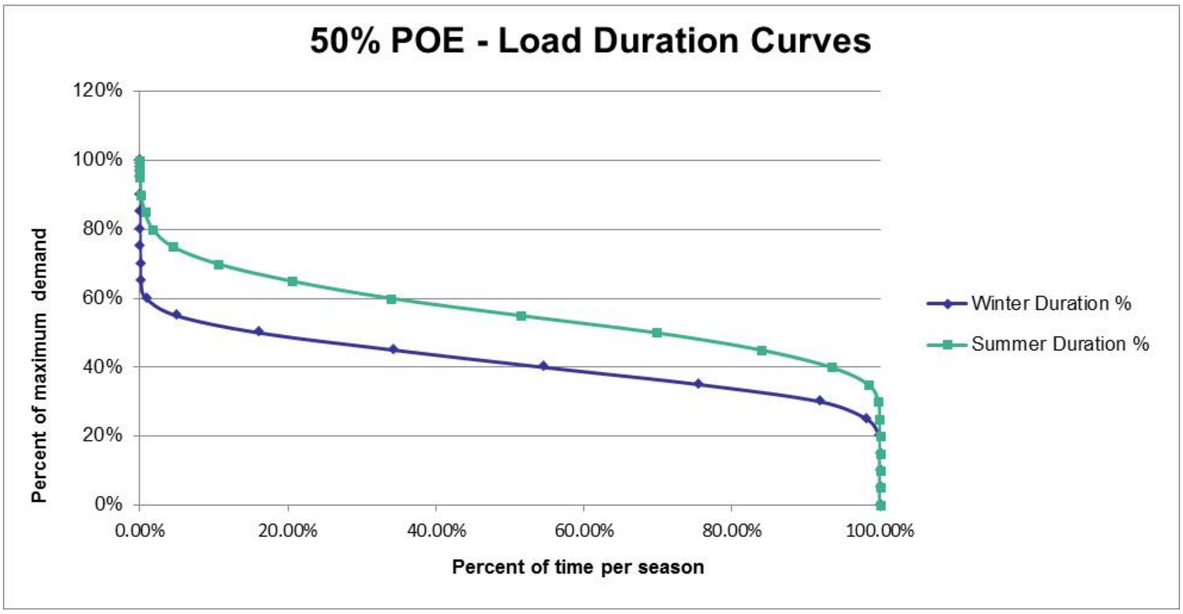

Figure 4: MFA 50% Load Duration Curves

The 10% POE unitised load duration for MFA zone substation is presented in Figure 5.

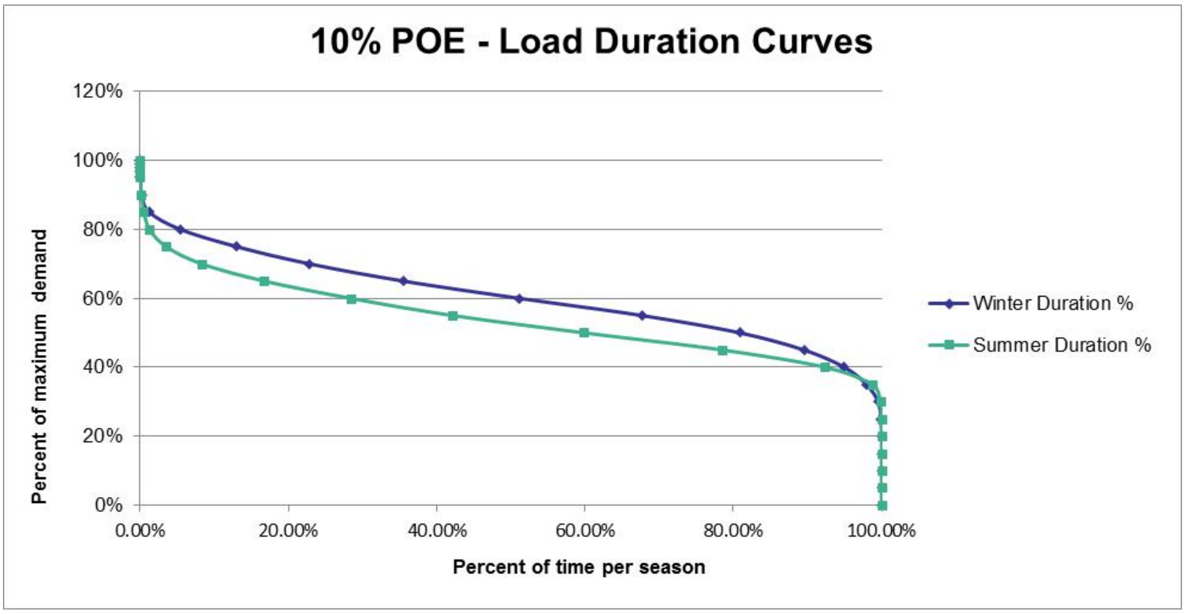

Figure 5: MFA 10% POE Load Duration Curves

2.7 Feeder Circuit Supply Capacity

There is currently no requirement for additional feeders at MFA due to the low load growth in the area.

2.8 Load Transfer Capability

The Distribution Annual Planning Report provides the load transfer capability (in MW) of the feeder interconnections between MFA and its neighbouring zone substations. Our forecast load transfer capability is presented in Table 4.

Table 4: MFA Load Transfer Capability

	2022	2023	2024	2025	2026	2027	2028
Load Transfer Capability (MW)	6.5	6.5	6.5	6.5	6.5	6.5	6.5

2.9 Station Configuration Supply Risk

The configuration of MFA means that failure of a 66/22kV transformer, 66kV circuit breakers, 22kV circuit breakers or 22kV current transformers will result in an immediate loss of all supplies from MFA until the failed equipment can be switched out, isolated and the station supplies restored.

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

Additionally, failure of any equipment will result in supply outages to customers as backup circuit breakers operate to isolate the failed equipment.

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

Table 5: MFA Bus Outage Consequence Factors

Equipment	Estimated Bus Outage Consequence
Transformer	100%
22kV circuit breaker	36%
66kV circuit breaker	33%
22kV current transformer	36%
66kV current transformer	33%
22kV voltage transformer	17%
66kV voltage transformer	17%

3 Identified need

MFA commenced operation in 1960 and the 66kV switchyard is practically unchanged. Our assessment is that the physical and electrical condition of a number of assets at MFA has deteriorated and are now presenting an increasing failure risk. The primary issues at MFA arise from the following asset-related risks:

a) Health and safety risks presented by a possible explosive failure of bushings on a number of the assets;

b) Plant collateral damage risks presented by a possible explosive failure of bushings on a number of the assets;

c) Environmental risks associated with insulating oil spill or fire;

d) Reactive asset replacement risks presented by the increasing likelihood of asset failure due to the deteriorating condition of the assets; and

e) Health and safety risks presented by cement sheets or electrical switch boards containing asbestos in the control building, storeroom and toilet.

The condition of the assets at MFA 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 MFA, 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]

Our planning report for MFA also highlighted the security of supply risks that arise from the station configuration, as all three transformers are switched as a single group. 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.

[1] For further details of the regulatory obligations that underpin the identified needs at MFA, please refer to section 4 of the notice of determination published on 7 April 2021.

4 Screening for non-network options

The purpose of the RIT-D is to identify the credible option for addressing an identified need that maximises the net market benefit. Clause 5.17.4(c) of the Rules states that a RIT–D proponent need not prepare a non-network options report if the proponent determines, on reasonable grounds, that there are no credible non-network options that are able to address the identified need, either partly or wholly. In accordance with this requirement, AusNet Services has determined that there are no non-network options that are capable of addressing the identified need.

Our reasoning for concluding that there are no credible non-network options are set out in our notice of determination under clause 5.17.4(d) of the Rules, which we published on 7 April 2021. In summary, in that notice we determined that:

- The nature of the risks are asset-related and cannot be mitigated by a non-network option.
- MFA is exposed to a security of supply issue arising from the existing station configuration. While this issue will need to be considered in addressing the preferred network solution, the potential exposure relates to the loss of the entire zone substation which cannot be addressed by a non-network solution.

In accordance with the Rules requirements, we also noted that these reasons are not dependent on any particular assumptions or methodologies.

5 Options considered

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. The options discussed in this section, which include both credible and non-credible options, are:

1. Do Nothing (counterfactual)
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 66kV circuit breakers
6. Replace No.3 transformer and 66kV circuit breakers
7. Replace and relocate No.2 transformer and 66kV circuit breakers
8. Replace two transformers and 66kV circuit breakers

The costs presented in this section are expressed in real 2022 dollars.

5.1 Option 1: Do Nothing

The Do Nothing (counterfactual) option assumes that AusNet Services 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 Do Nothing (counterfactual) option establishes the base level of risk, 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 NPV compared to the 'do nothing' 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 'Do Nothing' 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 MFA.

5.5 Option 5: Replace 66kV circuit breakers

This option includes replacement of assets for which deteriorated condition presents an increasing failure risk (except the 66 kV/22 kV power transformers). This includes five 66 kV minimum oil circuit breakers, all 66 kV current transformers and voltage transformers, and a 22 kV capacitor bank, which have all been assessed as being in condition C4 or C5. This option also allows for 66 kV busbar upgrades and selective replacement of insulators and support structures.

The associated protection and control systems will be replaced and housed in a new control room. The existing control building, battery room, toilets and stores building contain asbestos, so these buildings are to be replaced.

At the time of conducting the options analysis in 2019, this option deferred the installation of a 66 kV bus tie circuit breaker between the No. 2 and No. 3 power transformers, due to the space constraints within the existing 66 kV ring bus at MFA.

Through development of the detailed technical scope and cost estimate, it was found that in-situ replacement of the above components in the existing 66 kV ring bus has considerable constraints, including a limited outage window and limited space in the switchyard, so a greenfield solution is now proposed, with a new ring bus of irregular shape on land currently owned by AusNet Services and in addition acquiring adjacent land to avoid construction/installation constraints. Connection to the transformer bus is by new overhead lines.

The greenfield solution now allows for the installation of a 66 kV bus tie circuit breaker between the No. 2 and No. 3 power transformers and reduction of the risk to customer supply as a result of altering the existing ring bus configuration.

The scope for this option also includes replacement of the sixth 66kV CB ”A” which was previous assessed as C3 condition, whereas it is now regarded as critical to be replaced.

Based on the detailed cost estimate, the capital cost for this option is $18.52 million, including p50 risk, management reserve and overheads.

5.6 Option 6: Replace No.3 transformer and 66kV circuit breakers

This option replaces the existing No.3 transformer with a new 20/33MVA unit, replaces five existing 66kV circuit breakers and installs one new 66kV bus tie circuit breaker. It also allows for 66kV busbar upgrades and the replacement of deteriorated current transformers, capacitor bank and protection and control systems in a new control room. This option allows deferral of the No.2 transformer replacement.

As noted in relation to Option 5, the limited space in the switchyard would also require a greenfield solution. The estimated capital cost of this option is $22.99 million.

5.7 Option 7: Replace and relocate No.2 transformer and 66kV circuit breakers

This option replaces the existing No.2 transformer with a new 20/33MVA unit in a new location, replaces five existing 66kV circuit breakers and installs one new 66kV bus tie circuit breaker. It also allows for 66kV busbar upgrades and the replacement of deteriorated current transformers, capacitor bank and protection and control systems in a new control room. This option allows deferral of the No.3 transformer replacement.

As noted in relation to Option 5, the limited space in the switchyard would also require a greenfield solution. The estimated capital cost of this option is $23.37 million.

5.8 Option 8: Replace two transformers and 66kV circuit breakers

This option replaces the existing No.2 and No.3 transformers with two new 15/20MVA units, replaces five existing 66kV circuit breakers and installs two new 66kV bus tie circuit breakers.

It also allows for 66kV busbar upgrades and the replacement of deteriorated current transformers, capacitor bank and protection and control systems in a new control room. Under this option, assets with a high failure risk including the No.2 and No.3 66/22kV transformers, 66kV circuit breakers, and 22kV and 66kV current transformers are replaced as an integrated project.

This option also includes two extra 66kV outdoor bus-tie circuit breakers to improve station configuration and replace the existing capacitor bank and control room.

As noted in relation to Option 5, the limited space in the switchyard would also require a greenfield solution. The estimated capital cost for this option is $25.87 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 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 at MFA.

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. This market benefit is quantified in section 6.4.
(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.

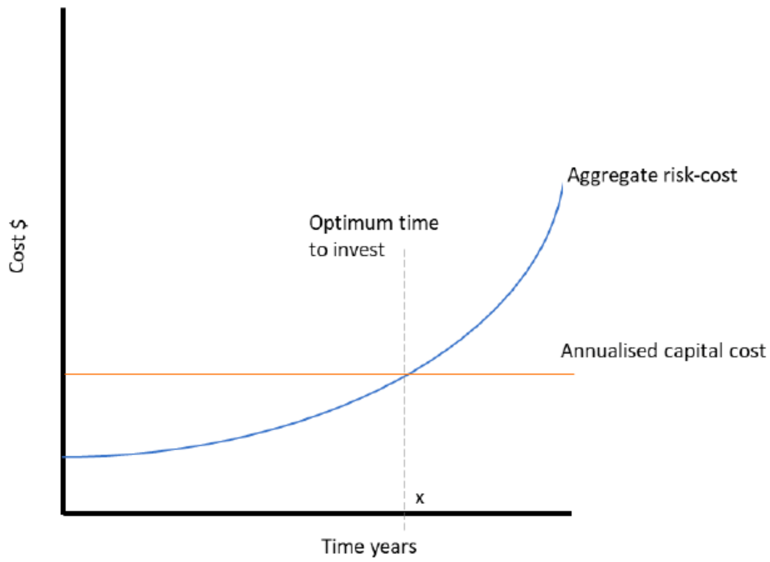

Figure 6: Increasing risk-cost over time and optimal project timing[2]

[2] 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.

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 as part of 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.[3] The relationship between sensitivity analysis and scenarios is best explained by the AER's practice note:[4]

> *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 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 are provided in the next section.

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[3] AER, Application guidelines, Regulatory investment test for distribution, December 2018, page 42.

[4] AER, Asset replacement planning, January 2019, page 36.

Table 7: Key variables and assumptions

Variable / assumption	Lower bound	Central estimate	Upper bound
Demand forecasts	5% reduction in central estimate of annual growth rate	Average annual growth rate of 1%	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 $44,566 per MWh[5]	25% increase in central estimate
Safety cost	Central Estimate	Value of statistical life of $4.5 million[6]	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[7]	2%	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 Services, MFA_V6.0_Economic_Model-Master_Template

6.4 Net present value 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

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5 Calculated using the latest VCR estimates for each sector.

6 Best Practice Regulation Guidance Note Value of statistical life, December 2014, escalated.

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

- Section 6.4.2 presents the sensitivity testing and scenarios analysis.

6.4.1 Net 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 2030. 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)

	2023	2024	2025	2026	2027	2028	2029	2030
Option 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Option 2	Not credible for the reasons set out in section 5.2							
Option 3	Not credible for the reasons set out in section 5.3							
Option 4	Not credible for the reasons set out in section 5.4							
Option 5	0.612	0.763	0.921	1.086	1.261	1.442	1.631	1.827
Option 6	0.426	0.583	0.747	0.918	1.099	1.286	1.481	1.684
Option 7	0.403	0.560	0.724	0.895	1.076	1.263	1.459	1.661
Option 8	0.334	0.497	0.668	0.847	1.036	1.233	1.438	1.652

Source: AusNet Services, MFA_V6.0_Economic_Model-Master_Template

While the above table is useful in understanding how the options compare with each other in the early years following implementation, the analysis required by the RIT-D must consider the relative performance of the credible options over the life of the asset.

In order to identify the preferred option, therefore, it is necessary to show the present value of the net economic benefit for each credible option. The table shows that the preferred option is Option 5, as it has the highest net economic benefit.

Table 9: Present value (PV) of the 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 credible for the reasons set out in section 5.2		
Option 3	Not credible for the reasons set out in section 5.3		
Option 4	Not credible for the reasons set out in section 5.4		
Option 5	44.71	17.87	26.84
Option 6	46.65	22.18	24.47
Option 7	46.65	22.54	24.11
Option 8	48.81	24.95	23.86

Source: AusNet Services, MFA_V6.0_Economic_Model-Master_Template

6.4.2 Sensitivity testing and scenario analysis

In addition to the above analysis, we also conducted sensitivity testing to examine how our assessment would be affected if certain parameters were varied. In particular, we considered variations in the risk of asset failure; demand; the cost of each option; and the weighted average cost of capital[8]. The results of this analysis is presented below.

Table 10: 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 credible for the reasons set out in section 5.2							
Option 3	Not credible for the reasons set out in section 5.3							
Option 4	Not credible for the reasons set out in section 5.4							
Option 5	51.97	7.49	28.25	25.43	24.16	29.52	15.77	66.13
Option 6	51.16	4.80	26.43	22.75	21.15	27.80	12.94	65.40
Option 7	50.80	4.52	26.07	22.39	20.73	27.49	12.58	65.03
Option 8	51.83	3.73	25.93	22.06	20.11	27.60	11.90	66.68

Source: AusNet Services, MFA_V6.0_Economic_Model-Master_Template

The sensitivity analysis shows that Option 5 continues to deliver a net economic benefit against each of these changes in parameter assumptions, apart from the low discount rate sensitivity, which shows that Option 8 is marginally preferred. 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

8 The discount rate used for the purpose of calculating the present value is a pre-tax real rate, with the lower bound consistent with the regulated cost of capital in the AER's decision for our distribution network (which is a nominal, vanilla WACC).

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 economic 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	26.84	25.43	66.16	29.20
Option 6	24.47	22.75	65.48	26.78
Option 7	24.11	22.39	65.17	26.36
Option 8	23.86	22.06	67.04	25.92

Source: AusNet Services, MFA_V6.0_Economic_Model-Master_Template

On the basis of this scenario analysis, Option 5 is preferred to the other options, apart from Option 8 which is preferred in a 'weak economic growth' scenario. The principal driver of the preference for Option 8 in this scenario is the assumed lower discount rate, as observed in our earlier sensitivity analysis. As Option 5 is preferred across the majority of the scenarios, we have selected it as our preferred option.

6.5 Preferred option

The results of the sensitivity testing confirm our finding that Option 5, being the replacement of five existing 66kV circuit breakers with AIS switchgear, is the preferred option. 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 compared to Option 5. As such, any variation in the costs of delivering Option 5 as a result of 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.

While our analysis indicates that the preferred option delivers benefits from 2022, to manage the deliverability and our capital expenditure throughout the 2021-25 EDPR, AusNet Services plans to commence work in relation to the preferred option during 2022-23, with completion expected in 2024-25. 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 $15.7 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	823.7	7,885.9	5.906.8	554.5	**15,170.9**

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 approximately $180k per annum.

In relation to the timetable for completing these works, we expect to publish the FPAR in April 2022, allowing the construction to commence from June 2022 onwards with commission readiness scheduled for 29 February 2024. The project is expected to reach completion by 31 May 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, clause 5.17.4(r)(1)(ii) is not applicable in this FPAR.

Table 15: Compliance with regulatory requirements

Requirement		Section
5.17.4(j) The draft project assessment report must include the following[9]:		
(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 2 provides the background information that underpins the identified need. No assumptions apply in relation to the identified need.
(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 6.4.1, Table 9.
(6)	a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure;	Section 5. As explained in section 6.4, the operating cost for each option is unchanged from the 'Do Nothing' option.
(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 1.2 and 6.5.
(11)	for the proposed preferred option, the RIT-D proponent must provide:	

9 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
(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);	As explained in section 6.4, the operating cost for each option is unchanged from the 'Do Nothing' option.
(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 A Preferred Option Details

Scope of work

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

Replacement of primary assets

- All 66kV switchyard equipment assessed as being in condition C4/C5 are to be replaced. This includes all 66kV minimum oil circuit breakers except for CB "A", all 66kV CTs and all CVTs. CB "A" is not recommended for replacement as it carries a C3 condition score but will nonetheless be replaced when the associated CTs are replaced using a dead tank CB.
- The high level scope calls for 66 kV isolators/disconnectors are to be replaced as appropriate. 66kV busbars are to be upgraded and insulators and support structures replaced where appropriate.
- At 22kV level, the capacitor bank and Tyree 22kV NCTs for No.2 & 3 transformers are to be replaced.
- The existing control building, battery room and amenities/store building has asbestos issues and are to be replaced.
- In-situ replacement was considered but faced the following constraints:
  - Limited outage window – The East Gippsland 66kV loop is constrained and heavily reliant on the larger TAURUS conductor MWTS-MFA and MWTS-SLE lines. The MFA ring bus cannot be broken for a sustained period as the smaller conductor lines are needed to cover the loss of any of the MWTS lines.
  - Limited space in switchyard – Many bays within existing ring bus are too cramped for the use of current standard Period Order equipment without breaching AS2067 section safety clearances.
- A greenfield solution is proposed in view of the constraints. A ring bus of irregular shape may be fashioned over an area west of the existing transformers form by combining:
  - an adjoining Lot 205 owned by AusNet leased to a towing company until June.
  - area now occupied by WiMax infrastructure which may be removed after AMI moves away from WiMax.
  - area released with a redesign and rebuilt of the TR1 22kV exit and shifting away 22kV feeder cables,
- As the entry to the transformer bus is from the east, it is proposed to connect the new ring bus to the transformer bus by O/H lines. The north side line has to be located outside the station for one span as there is no space within the station.
- Upgrade site fencing, switchyard lighting, surfaces, drainage, trenches to current standards

Replacement of secondary assets

- Replace MWTS, BDSS 1&2, SLE Line Prot with current standard panels having X 7SL87 & Y L90.
- Install TGN line, build one new cubicle to 2010 standard (EVX10/32/247) and transfer existing SEL311L and L90 relays over. This maintains the match with relays at remote TGN end for current differential protection.
- With a tie CB between the No.2 and 3 transformer, the standard protection panel may be used for the No.1/2 transformer group with slight modification on the 22kV side and the No.3 transformer. The transformer bus VTs can be removed and the protection is ready for the eventual replacement of the existing transformers by two 30MVA units.

- Install one wall-mounted panel in new control building for transformer cooler control.
- Install one new 22kV Capacitor Bank Prot panel using duplicate REF630.
- Relocate existing P29 housing MFA 22 VF Prot Signalling to Glenmaggie to new control building.
- Replace X&Y 125Vdc distribution board, 125V Battery and battery chargers. Obtain 48V from new DC system.
- Replace the 415V ac distribution board. This is configured as a sub-board to the 415kV Station Services Supply Cubicle in the 22kV switchroom.

Communications

It is necessary to maintain continuity of communications services while replacing the control building and demolishing the existing building. To achieve this, it is necessary to install new equipment in the new control building, commission them and progressively migrate existing services. It should be noted that SDH Equipment from ZTE, which forms the base of the existing network, is no longer available in the market. A new Communications Network Loop will be established making use of XTRAN Equipment.

Sequencing of works

At a high level the project stages will be as follows:

1) Aggregate area for greenfield 66kV switchyard by:
   - Giving notice to tenants on Lot 205, extend substation bench westwards, fencing up area
   - Demolish and remove AMI pole.
2) Rebuild 22kV pole and cable exit from the No.1 Transformer, relocate 22kV feeder cables
3) Install new modular capbank
4) Build greenfield 66kV switchyard
5) Install new modular control building and battery enclosure
6) Complete all testing
7) Divert 66kV O/H lines starting with TGN. Connect new and old 66kV ring bus.
8) Divert BDSS 2, MWTS, 2nd connection between new and old 66kV ring, SLE and BDSS 1.
9) Remove redundant equipment.

Technical assumptions

The following technical assumptions and clarifications are made:

- All rating, sizing, plant and cable, dimensioning and volume allowance of materials and areas is for business case estimation purposes and not to be used as a design scope. All rating and sizing calculations are to be completed and verified during detailed design.
- The staging is for business case estimation purposes and not to be used as a design scope. The actual staging is to be reviewed against fresh load information and verified during construction.
- The existing transformer bus is reused.
- The rebuild cable support structure for the No.1 transformer may encroach slightly into the access road.
- The new SCIMS panels will have adequate serial/ ethernet ports to interface the new IED's being added as part of the project.