Planning Report Maffra (MFA) Zone Substation

AMS – Electricity Distribution Network

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Please contact the indicated owner of the document with any inquiries.

T Langstaff
AusNet Services
Level 31, 2 Southbank Boulevard
Melbourne Victoria 3006
Ph: (03) 9695 6000

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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).

This report presents our forward looking investment plans to manage the existing and emerging service level constraints in the Maffra (MFA) Zone Substation supply area. This plan is developed to ensure that we maintain service levels to our customers over the short and long term. The report outlines how we quantify service risk, identifies and assesses the costs and benefits of potential options to mitigate the identified risks, and provides forward looking plans outlining the optimal service risk mitigation solutions, and timing of those solutions, to maintain service levels.

1.1 Identified Need

Maffra Zone Substation (MFA) commenced operation as a 66/22kV transformation station in 1960. The two 10/13.5MVA transformers were installed in 1960 and a third 10/13.5MVA transformer was added in 1998. The 66kV switchyard was constructed in the 1960s. The 22kV switchyard was replaced by an indoor switchboard in 1998.

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, however all three transformers are switched as a single group, hence faults on the 66kV transformer bus or any one of the transformers will result in a loss of supply to all customers.

The key service constraints at MFA are:

- Security of supply risk presented by the switching of the three 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 asbestos containing cement sheets or electrical switch boards in the control building, store room and toilet.

1.2 Proposed Preferred Option

The options analysis identifies that the preferred option, being the one that maximises the net economic benefit to all those that produce, consume and transport electricity in the NEM, is to:

- Replace the 66kV circuit breakers by 2020, at an estimated capital cost of [C.I.C] (Real $2018).

Applying a discount rate of 6.44% per annum, this proposed preferred option has a net economic benefit of [C.I.C], relative to the Do Nothing Different option, over the forty-five-year assessment period.

1.3 Next Steps

This planning report outlines the service level risk mitigation investment that AusNet Services has assessed as prudent, efficient and providing the optimal balance of supply reliability and cost.

While this report outlines AusNet Services' plans for maintaining service levels, and serves to support AusNet Services' revenue request for the 2022-26 EDPR period, the proposed investment is subject to the regulatory investment test for distribution (RIT-D).

As such, the proposed investment will be confirmed via the formal RIT-D process, which includes publication of up to three reports at the various RIT-D stages, and includes a formal consultation process where interested parties can make submissions that help identify the optimal solution.

2 Introduction

2.1 Purpose

This planning report outlines asset condition, asset failure risks and network development plans relevant to Maffra (MFA) Zone Substation for the period from 2022 to 2026.

It provides an analysis of viable options to address the identified risks and maintain the efficient delivery of electrical energy from MFA consistent with the National Electricity Rules (NER) and stakeholder's requirements.

It also summarizes the scope, delivery schedule and expenditures associated with the most economical solution to emerging constraints.

2.2 Scope

The scope of this planning report is limited to the equipment within Maffra (MFA) Zone Substation.

It excludes sub-transmission and distribution feeders entering and exiting the zone substation.

2.3 Asset Management Objectives

As stated in *AMS 01-01 Asset Management System Overview*, the high-level asset management objectives are:

- Comply with legal and contractual obligations;
- Maintain safety;
- Be future ready;
- Maintain network performance at the lowest sustainable cost; and
- Meet customer needs.

As stated in *AMS 20-01 Electricity Distribution Network Asset Management Strategy*, the electricity distribution network objectives are:

- Improve efficiency of network investments
- Maintain long-term network reliability
- Implement REFCLs within prescribed timeframes
- Reduce risks in highest bushfire risk areas
- Achieve top quartile operational efficiency
- Prepare for changing network usage.

3 Background

3.1 Substation Description

Maffra (MFA) is located approximately 220km 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 30m 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 rain fall varies from 41mm to 63mm 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 Maffra Zone Substation is a milk processing plant owned by [C.I.C]. This plant is a major employer in the community and performs an essential role for the regions dairy producers. The electrical supply to the plant is critical to compliant operation of sensitive milk processing equipment.

A special switching arrangement at Maffra Zone Substation 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 [C.I.C] and provides protection to the plant from power vairations 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 (TGN) Zone Substation; and
- Sale (SLE) Zone Substation.

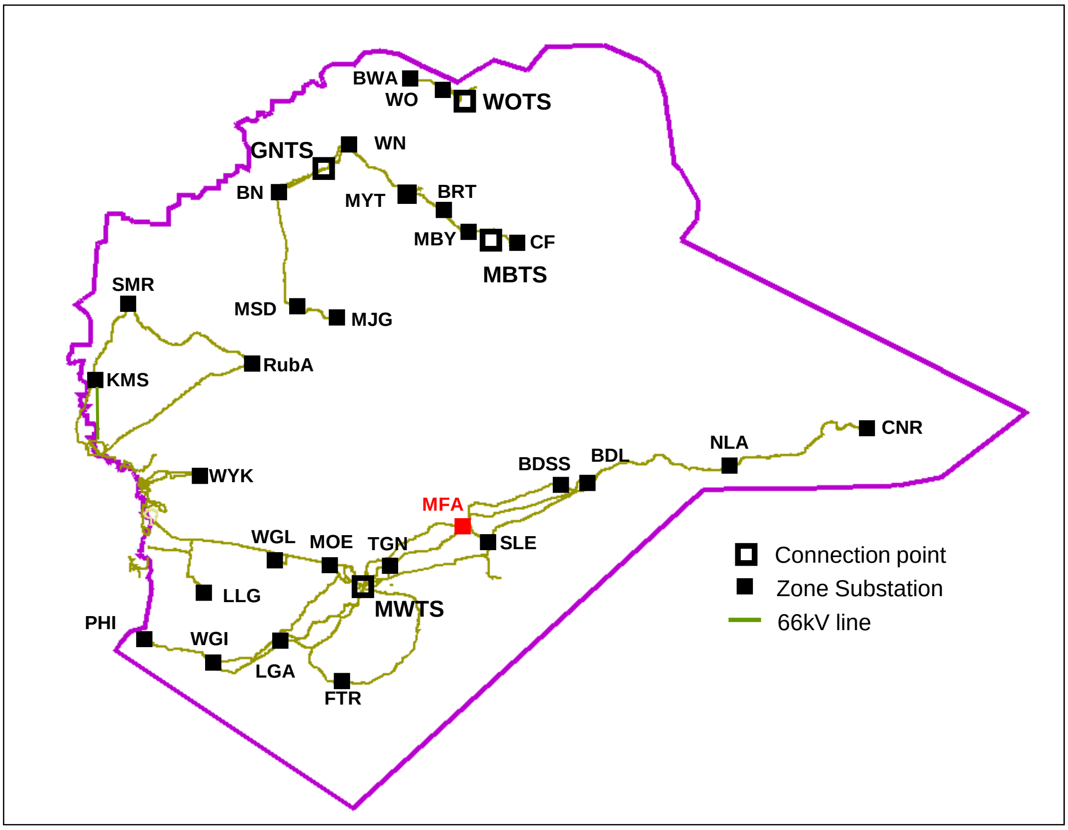

Figure 1: MFA location within AusNet Services subtransmission network

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

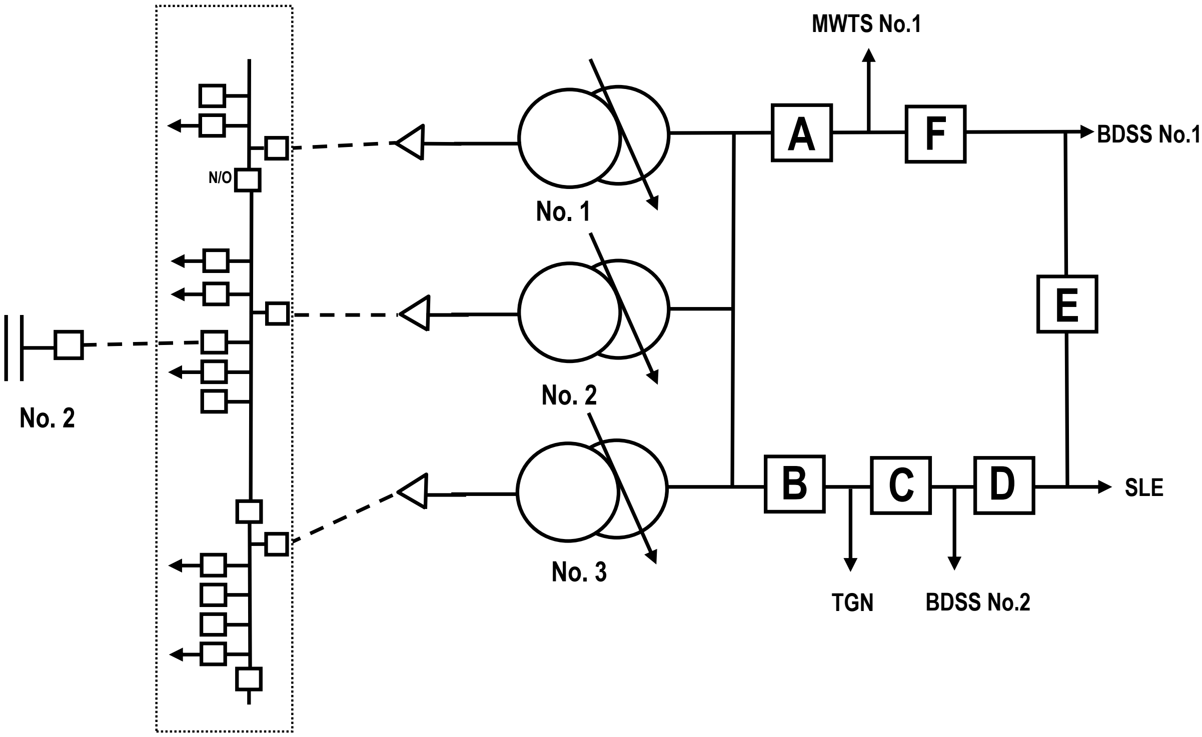

Figure 2: Single Line Diagram of MFA

3.2 Customer Composition

MFA has six 22kV feeders supplying AusNet Services' customers. Table 1 provides detail 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
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.

3.3 Zone Substation Equipment

3.3.1 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 is 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, which comprises 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.

3.3.2 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.

The 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.

The bus protection has overcurrent and distance protection using old digital relays.

3.4 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 condition is provided in Table 3 and discussed in the following sections.

Table 3: MFA Asset Condition Summary

Asset Type	Number of Assets				
	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.

3.5 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.

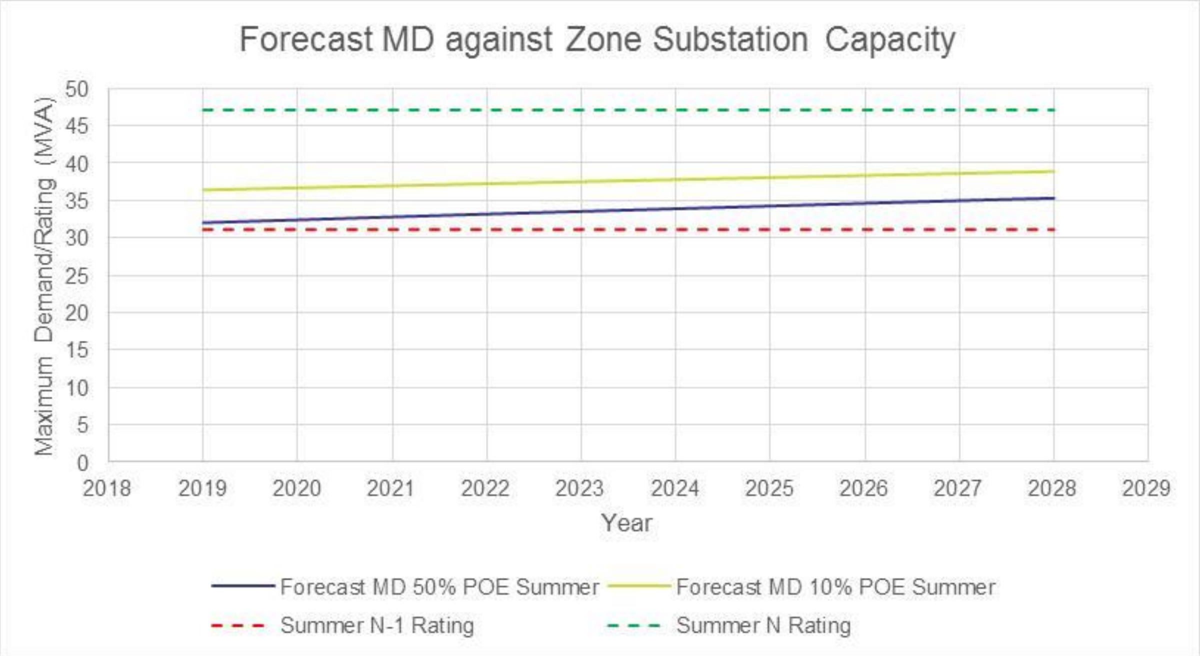

Figure 3: MFA Forecast Maximum Demand against Zone Substation Capacity

3.6 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 2016 and 31 March 2017 for the summer 50% probability of exceedance (POE) curves;
- 1 April 2017 and 30 September 2017 for the winter 50% POE curves;
- 1 October 2013 and 31 March 2014 for the summer 10% POE curves; and

- 1 April 2017 and 30 September 2017 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 MFA zone substation is presented in

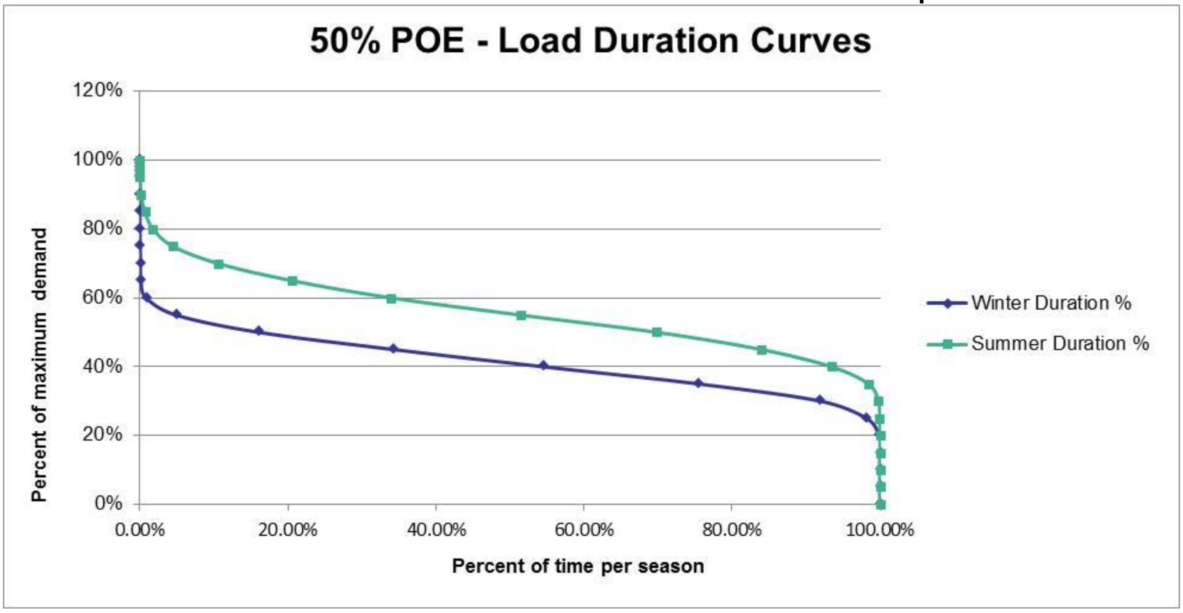

Figure 4, and the 10% POE unitised load duration for MFA zone substation is presented in Figure 5.

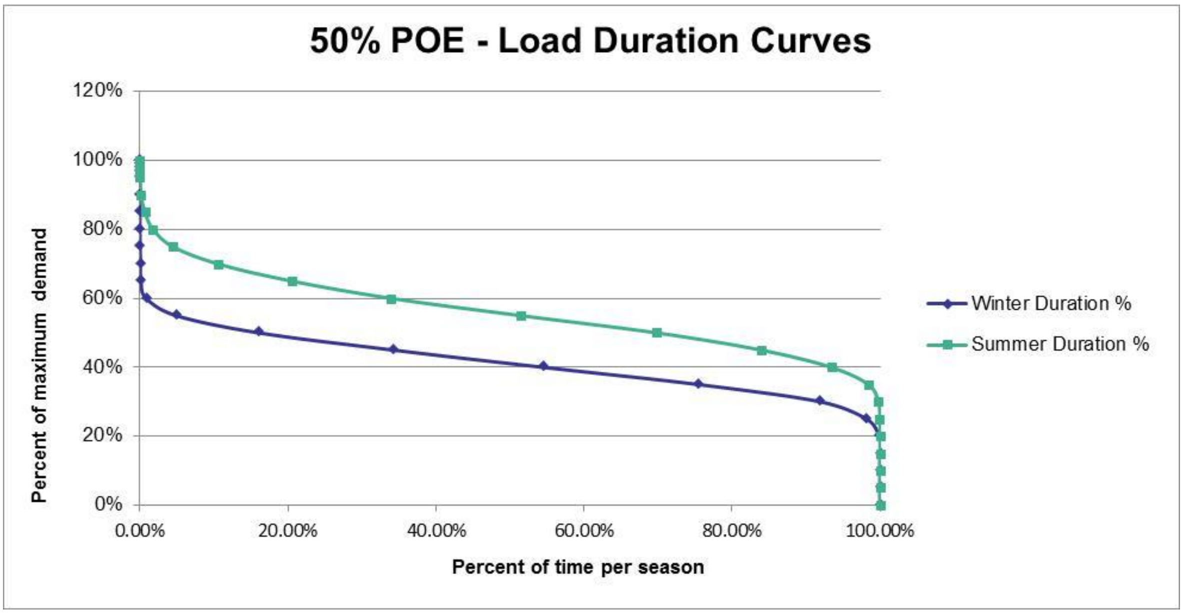

Figure 4: MFA 50% Load Duration Curves

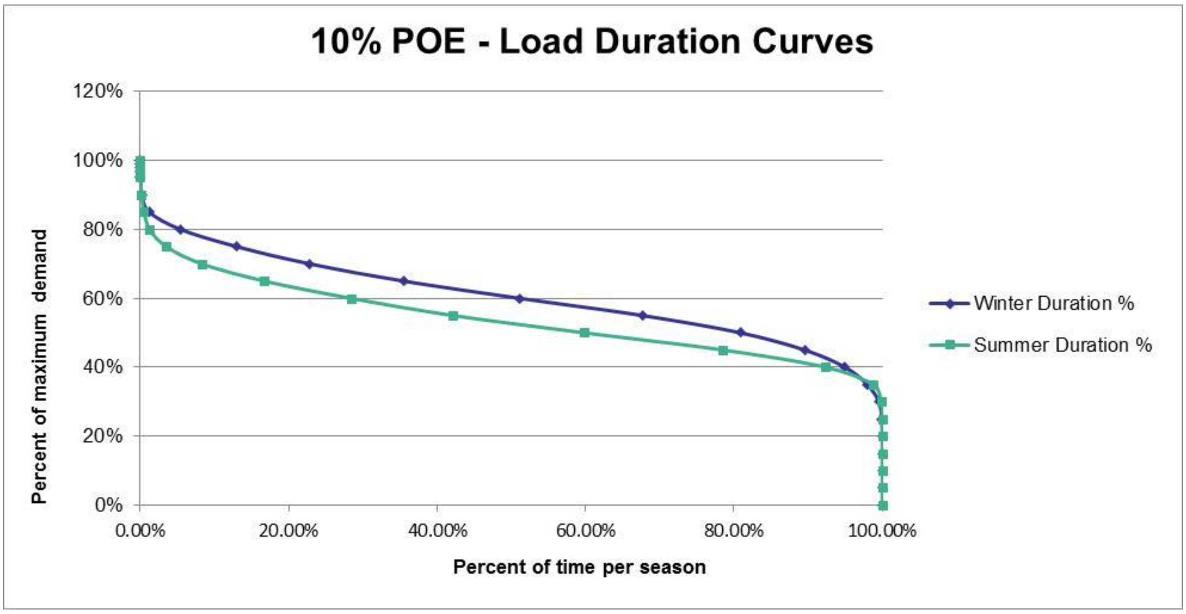

Figure 5: MFA 10% POE Load Duration Curves

3.7 Feeder Circuit Supply Capacity

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

3.8 Load Transfer Capability

The Distribution Annual Planning Report (DAPR) provides the load transfer capability (in MW) of the feeder interconnections between MFA and its neighbouring zone substations.

This is then forecast forward in line with the forecast demand growth to give the forecast load transfer capability in Table 4.

Table 4: MFA Load Transfer Capability

	2019	2020	2021	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	6.5	6.5	6.5

4 Other Issues

4.1 Regulatory Obligations

This planning report acknowledges AusNet Services obligations as a Distribution Network Service Provider under the National Electricity Rules with particular emphasis on:

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.*

4.2 Station Configuration Supply Risk

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

This 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%

5 Identified Need

MFA commenced operation as a 66/22kV transformation station in 1960. The two 10/13.5MVA transformers were installed in 1960 and a third 10/13.5MVA transformer was added in 1998. The 66kV switchyard is practically as it was constructed in the 1960s. The 22kV switchyard was replaced by an indoor switchboard in 1998.

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, however all three transformers are switched as a single group, hence faults on the 66kV transformer bus or any one of the transformers will result in a loss of supply to all customers.

The key service constraints at MFA are:

- Security of supply risk presented by the switching of the three 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 asbestos containing cement sheets or electrical switch boards in the control building, store room and toilet.

6 Risk and Options Analysis

6.1 Risk-Cost Model Overview

AusNet Services' risk-cost model quantifies the benefits of potential investment options by comparing the service level risk of the Do Nothing (Counterfactual) option with the reduced service level risk assuming the credible option is place.

The investment cost to implement the credible option is then subtracted from the monetised benefit to compare credible options and identify the option that maximises the net economic benefit (the proposed preferred option).

The areas of service level risk costs, and risk cost reduction benefits, that AusNet Services considers include:

- Supply risk;
- Safety risk;
- Collateral damage risk;
- Reactive replacement risk;
- Environment risk;
- Operations and maintenance costs; and
- Losses.

Further details on this model can be found in AusNet Services' Risk-Cost Assessment Model Methodology paper.

6.2 Risk Mitigation Options Considered

This section outlines the potential options that have been considered to address the identified service level risk and need to invest, and summarises the key works and costs associated with implementing these options.

It presents both the credible and non-credible options considered, and, where relevant, outlines why particular option are considered non-credible.

The following options have been identified to address the risk at MFA:

1. Do Nothing Different (counterfactual)
2. Retire one transformer
3. Retire one transformer and sure up supply capacity via 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

An economic cost-benefit assessment is used to assess and rank the economic efficiency of each option.

The following sections provide a brief summary of each of these options.

6.2.1 Option 1: Do Nothing Different

The Do Nothing Different (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 Different (counterfactual) option establishes the base level of risk, and provides a basis for comparing potential options.

Since this option assumes no investment outside of the normal operational and maintenance processes, this is a zero investment cost option.

6.2.2 Option 2: Retire one transformer

This options 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 capital cost for this option is [C.I.C], for associated decommissiong works.

6.2.3 Option 3: Retire one transformer and sure up supply capacity via network support

This option tests whether the current installed capacity of the substation is still required to meet customer demand and whether equipment could be retired and network support used rather than replacing poor condition assets.

The capital cost for this option is [C.I.C], for associated decommissiong works and setup of a 10MW network support agreement.

In addition to the capital cost, there is ongoing operational costs associated with this option that represent the network support availability and activation costs, and which vary year-by-year based on the network support expected under this option, as outlined in Table 6.

Table 6: Network support services annualised costs ($ million)

2021	2022	2023	2024	2025
C.I.C				

6.2.4 Option 4: Network support to defer retirement and replacement

This options tests whether network support can be used to defer the replacement of poor condition assets. This option addresses the supply risks associated with poor condition assets, but does not address the safety, environmental or collateral damage risks as the assets remain in service.

The capital cost of this option is [C.I.C], for setup of a 10MW network support agreement.

In addition to the capital cost, there is ongoing operational costs associated with this option that represent the network support availability and activation costs, and which vary year-by-year based on the network support expected under this option, as outlined in Table 7.

Table 7: Network support services annualised costs ($ million)

2021	2022	2023	2024	2025
C.I.C				

6.2.5 Option 5: Replace 66kV circuit breakers

This option replaces five existing 66kV circuit breakers with air insulated switchgear (AIS) switchgear. This could only be achieved by deferring the 66kV bus tie installation due to the space constraints within the existing 66kV ring bus at MFA.

This option also allows for the replacement of deteriorated current transformers, capacitor bank and protection and control systems in a new control room.

The capital cost for this option is [C.I.C].

6.2.6 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.

The capital cost of this option is [C.I.C].

6.2.7 Option 7: Replace 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.

The capital cost of this option is [C.I.C].

6.2.8 Option 8: Integrated Replacement

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.

The No.2 and No.3 transformer are replaced with two new 15/20MVA units. Five deteriorated 66kV circuit breakers are replaced and 66kV busbars are upgraded.

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.

The capital cost for this option is [C.I.C].

6.3 Risk-Cost Model Results

6.3.1 Existing Service Level Risk

Figure 6 shows the existing service level risk. The risk costs are dominated by supply risk but also have a significant amount of non-supply risks (safety, environment, collateral damage and reactive replacement). The escalation in the risk costs over time is driven by deterioration in the condition of the assets.

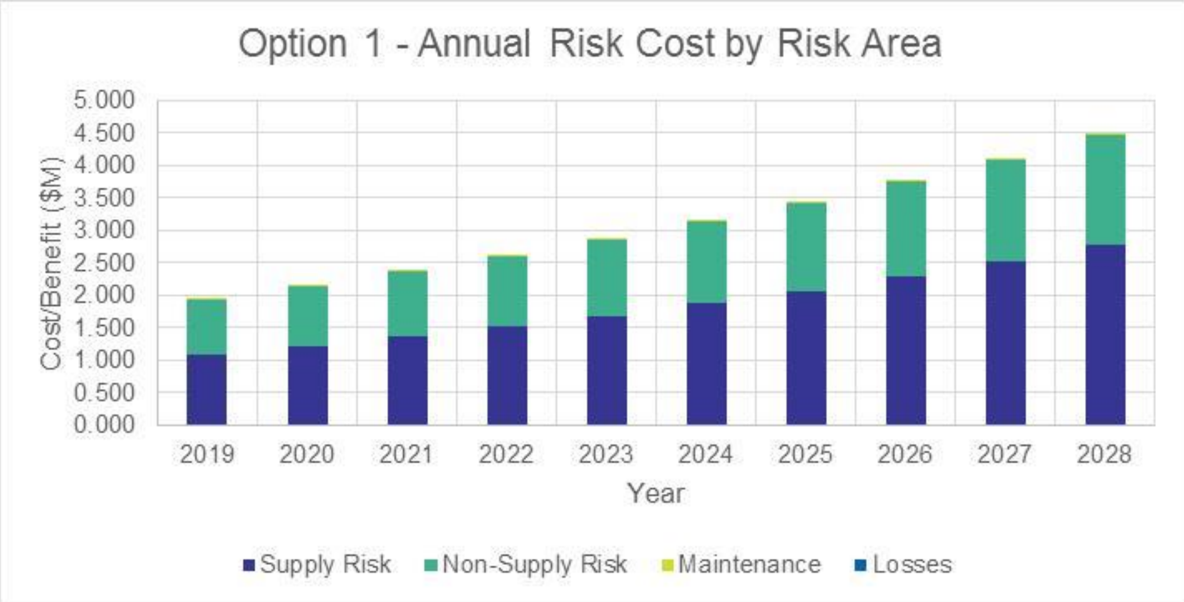

Figure 6: Do Nothing Different – Service Level Risk Cost

6.3.2 Economic Cost Benefit Analysis

The economic analysis allows comparison of the economic cost and benefits of each option to rank the options and to determine the economic timing of the preferred option.

It quantifies the capital, operational and maintenance costs along with service level risk reduction benefits for each option.

Table 8 lists the annualised net economic benefit of each option for each year, with the option that maximises this benefit highlighted.

Table 8: Annualised net economic benefit ($M)

<table>
<tr><th></th><th>2020</th><th>2021</th><th>2022</th><th>2023</th><th>2024</th><th>2025</th><th>2026</th><th>2027</th><th>2028</th></tr>
<tr><td>Option 1</td><td>0.000</td><td>0.000</td><td>0.000</td><td>0.000</td><td>0.000</td><td>0.000</td><td>0.000</td><td>0.000</td><td>0.000</td></tr>
<tr><td>Option 2</td><td rowspan="7" colspan="9">C.I.C</td></tr>
<tr><td>Option 3</td></tr>
<tr><td>Option 4</td></tr>
<tr><td>Option 5</td></tr>
<tr><td>Option 6</td></tr>
<tr><td>Option 7</td></tr>
<tr><td>Option 8</td></tr>
</table>

This indicates that Option 5 is the most economic option prior to 2028, with Option 6 becoming the most economic option in 2028.

6.3.3 Sensitivity Analysis

Table presents the net present value of net economic benefits under a variety of sensitivities. The net economic benefit assessment takes account of each option's total capital, operating and maintenance costs, compared to the reduction in service level risk cost that option is expected to deliver.

The robustness of the economic assessment is tested for the following sensitivities:

- Asset failure rates, varied at ±50% of the base failure rate;
- Maximum demand forecasts, varied to ±5% of the base forecast;
- Value of customer reliability (VCR), varied to ±25% of the base VCR;
- Proposed option costs, varied to ±15% of the base option cost;
- Value of statistical life (VoSL) of [C.I.C], varied from a [C.I.C] low case, to a [C.I.C], high case; and
- Discount rate of 6.44%, varied to ±2% per annum of the base discount rate.

The preferred option under each sensitivity is highlighted, and the option that maximises net benefits under the majority of sensitivities is considered the proposed preferred option.

Table 9: NPV of Net Economic Benefit Analysis

<table>
<tr><th>Scenario</th><th>Option 1</th><th>Option 2</th><th>Option 3</th><th>Option 4</th><th>Option 5</th><th>Option 6</th><th>Option 7</th><th>Option 8</th></tr>
<tr><td>Base Case</td><td>$0.00</td><td colspan="7" rowspan="13">C.I.C</td></tr>
<tr><td>High Asset Failure Rate</td><td>$0.00</td></tr>
<tr><td>Low Asset Failure Rate</td><td>$0.00</td></tr>
<tr><td>High Demand</td><td>$0.00</td></tr>
<tr><td>Low Demand</td><td>$0.00</td></tr>
<tr><td>High VCR</td><td>$0.00</td></tr>
<tr><td>Low VCR</td><td>$0.00</td></tr>
<tr><td>High Option Cost</td><td>$0.00</td></tr>
<tr><td>Low Option Cost</td><td>$0.00</td></tr>
<tr><td>High VoSL</td><td>$0.00</td></tr>
<tr><td>Low VoSL</td><td>$0.00</td></tr>
<tr><td>High Discount Rate</td><td>$0.00</td></tr>
<tr><td>Low Discount Rate</td><td>$0.00</td></tr>
</table>

The sensitivity analysis indicates the preferred option is Option 5, as it has the highest net benefit under the majority of sensitivities tested.

6.3.4 Optimal Economic Timing of Proposed Preferred Option

The annual benefit of implementing a credible alternative option to the Do Nothing Different (counterfactual) is the difference between total service level risk cost with a credible option in place, and the total service level risk cost of the Do Nothing Different option.

The optimal economic timing of the proposed option is the point in time when the annual benefit of implementing the proposed option outweighs the annualised cost to implement that option.

The optimal economic timing to implement the proposed preferred option is by 2020, as presented in Figure 7.

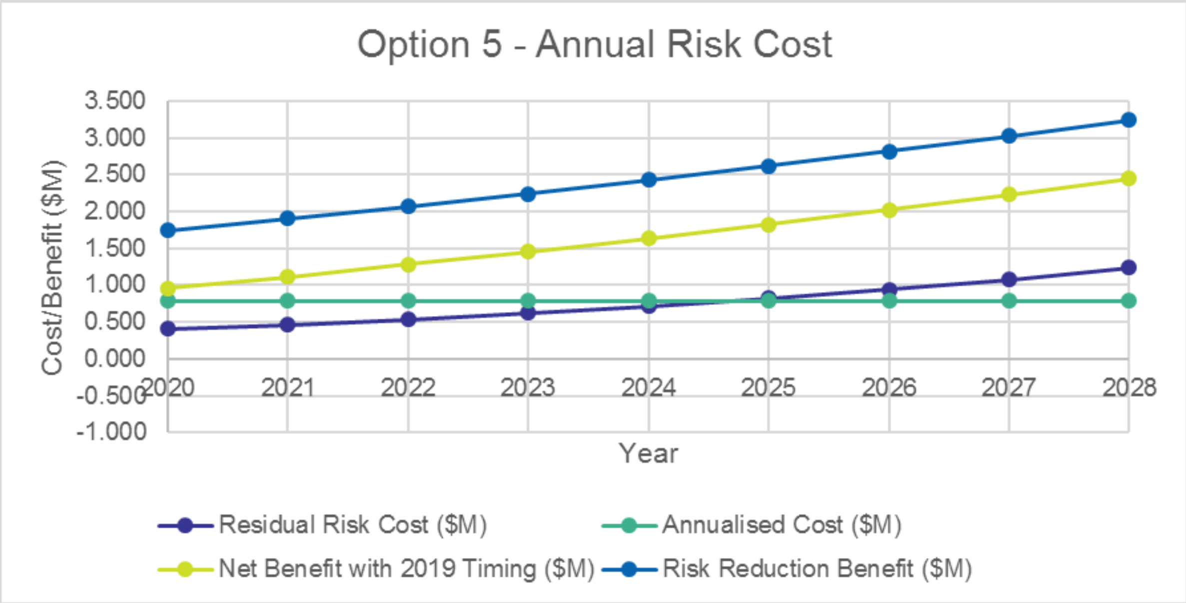

Figure 7: Economic timing of the proposed preferred option

7 Conclusion and Next Steps

The assessment outlined in this report shows that the service level risk to customers supplied from Maffra (MFA) Zone Substation is forecast to grow to unacceptable levels within the 2022-26 EDPR period.

The forecast increase in service level risk is driven by increasing supply and non-supply (safety, environmental, collateral damage and reactive replacement) risk driven by deterioration in the condition of the assets resulting in an increasing likelihood of asset failure.

7.1 Proposed Preferred Option

The options analysis identifies that the preferred option, being the one that maximises the net economic benefit to all those that produce, consume and transport electricity in the NEM, is to:

- Replace the 66kV circuit breakers by 2020, at an estimated capital cost of [C.I.C] (Real $2018).

Applying a discount rate of 6.44% per annum, this proposed preferred option has a net economic benefit of [C.I.C], relative to the Do Nothing Different option, over the forty-five-year assessment period.

While the optimal timing of the proposed preferred option is by 2020, to manage the deliverability, allow sufficient time to complete the required regulatory investment test for disctrubition (RIT-D), and to spread the capital expenditure throughout the 2022-26 EDPR, AusNet Services plans to implement the proposed preferred option by 2022.

7.2 Next Steps

This planning report outlines the service level risk mitigation investment that AusNet Services has assessed as prudent, efficient and providing the optimal balance of supply reliability and cost.

While this report outlines AusNet Services' plans for maintaining service levels, and serves to support AusNet Services' revenue request for the 2022-26 EDPR period, the proposed investment is subject to the regulatory investment test for distribution (RIT-D).

As such, the proposed investment will be confirmed via the formal RIT-D process, which includes publication of three reports at the various RIT-D stages, and includes a formal consultation process where interested parties can make submissions that help identify the optimal solution.

Appendix A Preferred Option Details

A.1 Scope of Work

- Replace the existing five 66kV minimum oil circuit breakers (CB “B”, “C”, “D”, “E” and “F”) and associated [C.I.C] current transformers,
- Replace the existing three [C.I.C] 66kV single phase current transformers of CB “A” and the [C.I.C] 22kV neutral current transformers of the No.2 and No.3 transformers,
- Upgrade the existing 66kV busbars and selectively replace the insulators and support structures,
- New capacitor bank, battery room and amenities building,
- Associated 66kV protection works in a new control room,
- Upgrade site fencing and security to current medium risk security standards,
- Upgrade switchyard lighting, surfaces, drainage, trenches to current standards.

A.2 Project Cost Summary

Design	
SPA internal costs	
Sub-contractor indirects	
66kv equipment	
22kv equipment	
Transformers	
Line works	
Infrastructure - civil works	
Infrastructure - building works	
Infrastructure - services	
Protection & control systems	
Land / easement purchase	C.I.C
Metering cost	
Outages	
Spares	
Nominal risk allowance	
Project direct costs	
Management contingency	
Project direct costs plus contingency	
Overheads	
Finance charges	
Operating expenditure	
WDV (written down value) of assets to be retired	
Total	