MANAGING THE RISK OF TRANSFORMER BUSHING FAILURE

Project Specification Consultation Report

22 August 2018

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Executive Summary

We have identified to need to replace about 100 transformer bushings on 18 power transformers across South Australia

This Project Specification Consultation Report (PSCR) identifies the need to replace 101 transformer bushings fitted on 18 power transformers across ElectraNet's transmission network based on their condition. The bushings were installed in the 1960s and 1970s and are now reaching, or past, the end of their technical lives. The bushings are now between 36 and 55 years old compared to a standard technical life of 40 years.

The identified transformer bushings are located at the following ten substations:

- Metropolitan substations – Para, Cherry Gardens and LeFevre; and
- Rural substations – Robertstown, Snuggery, Yadnarie, Murray Bridge/ Hahndorf PS1, Murray Bridge/ Hahndorf PS3, Berri and North West Bend.

The 'identified need' is to efficiently manage the risk of asset failure

The identified need for this project is to manage the risk of failure of individual transformer bushings that are reaching, or have passed, the end of their technical lives based on their condition.

We assess the condition and required timing of replacement of transformer bushings as part of our ongoing asset management processes. There is an increased likelihood that a number of these assets will fail within the next 5-10 years, which could result in unplanned outages on parts of the transmission network. Relevantly, on 3 August 2018, one of the transformer bushings identified as requiring replacement as part of this assessment suffered an explosive failure.

The potential consequences of transformer bushing failure include oil-fuelled fire with consequential damage to the transformer and other equipment, as well as safety risk to network personnel and the wider community. In a severe scenario, the failed bushing can result in significant unserved energy for electricity customers because of the transformer itself completely failing.

We have classified this RIT-T as a market benefits driven RIT-T because, while the aim is to maintain the quality, reliability and security of supply of prescribed transmission services, the economic assessment is not driven by the requirement to meet a mandated reliability standard. Rather a full cost benefit assessment has been undertaken, comparing the risk cost reduction benefits of asset replacement options with the cost of those options.

Asset replacement is the only feasible solution that can meet the identified need

There is only one technically and economically feasible option, which is to replace the end-of-life transformer bushings on a like-for-like basis. This is because bushings play a very specific role in enabling transformers to operate and, without them, transformers, and hence substations, cannot fulfil their role of transforming electrical voltages to higher or lower levels for efficient electrical power transportation to downstream transmission and distribution end-use customers.

We have investigated two credible options with different timing for the proposed replacement program:

- Option 1 – Replace identified transformer bushings between 2018-19 and 2021-22; and
- Option 2 – Defer replacement of the transformer bushings to the following regulatory period and replace them between 2023-24 and 2026-27.

Both options cost approximately $6.86 million ($2017/18) and are expected to take 2.5 to 3 years to be completed. Although Option 2 has a lower cost, in present value terms, than Option 1, it comes with a higher expected risk associated with keeping the identified bushings in-service for an additional five years.

There is no feasible role for network support solutions in addressing the identified need for this RIT-T

Network support solutions cannot credibly meet the identified need for this RIT-T. This is because of the specific role that the identified bushings play in the transmission of electricity and their relatively low replacement cost.

A network support option that avoids replacement of the identified transformer bushings would need to effectively replace the functionality, capacity and reliability of the entire transformer substation on an ongoing basis at a cost that is lower than the network option currently under consideration. The total capital cost of replacing all 101 identified bushings is estimated to be $6.86 million (approximately $686,000 per substation or $68,000 per bushing).

For completeness, this PSCR sets out in more detail the required technical characteristics for a network support solution.

Three different 'scenarios' have been modelled to deal with uncertainty

We have developed three scenarios to assess the two credible options for replacing the identified transformer bushings as shown in Table 1.

Table 1 Summary of the three scenarios

Key variable/parameter	Low benefits scenario	Central scenario	High benefits scenario
Capital costs	130 per cent of capital cost estimate	Base estimate	70 per cent of capital cost estimate
Commercial discount rate[1]	8.38 per cent	6 per cent	3.62 per cent
Avoided 'risk cost' benefit	70 per cent of base estimates	Base estimates	130 per cent of base estimates
Deferred routine bushing tests	70 per cent of base estimates	Base estimates	130 per cent of base estimates
Avoided corrective maintenance	70 per cent of base estimates	Base estimates	130 per cent of base estimates

[1] Expressed on a pre-tax real basis.

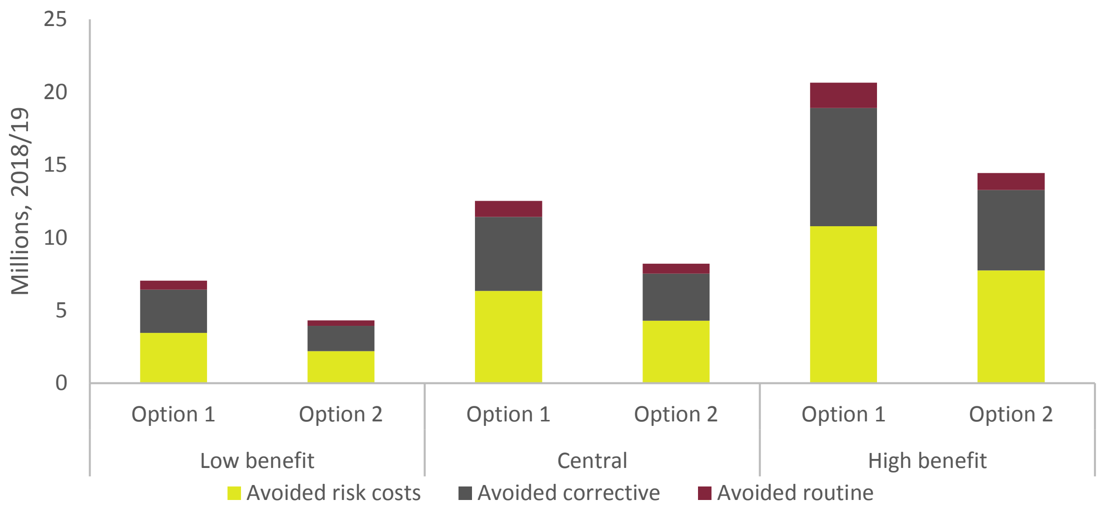
These describe:

- a ‘central’ scenario – reflecting our base set of key assumptions;
- a ‘low benefits’ scenario – reflecting a conservative set of assumptions, which represents a lower bound on potential market benefits that could be realised under each credible option; and
- a ‘high benefits’ scenario – reflecting an optimistic set of assumptions, which represents an upper bound on potential market benefits that could be realised under each credible option.

Replacing the identified bushings in the next five years is the preferred option[2]

The preferred option that has been identified in this assessment for addressing the identified need is Option 1; i.e. replacing the identified transformer bushings between 2018-19 and 2021-22. Option 1 has greater estimated gross benefits than Option 2 because the identified bushings are being replaced approximately five years earlier than under Option 2. Most of the benefits are attributable to avoiding the risk costs of transformer bushing failure and avoided corrective maintenance, while avoided routine maintenance costs (i.e. deferred routine bushing tests) contribute relatively small amounts to the estimated benefits.

Figure 1 – Breakdown of present value gross economic benefits of Option 1 and Option 2



We have also undertaken a thorough sensitivity testing exercise to understand the robustness of the RIT-T assessment to underlying assumptions about each of the key variables.

In particular, we have looked at the consequences for the credible options of ‘getting it wrong’ if the key underlying assumptions are not accurate; e.g. if avoided ‘risk costs’ are not as great as assumed.

For all sensitivity tests undertaken, the estimated net market benefit of Option 1 exceeds that for Option 2. Furthermore, the estimated net market benefits are found to be positive for both of the credible options over all of the sensitivities investigated.

[2] The preferred option is defined as the option that maximises net market benefits under the RIT-T framework.

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Glossary of Terms

Term	Description
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ETC	Electricity Transmission Code
NPV	Net Present Value
NEM	National Electricity Market
NER, Rules	National Electricity Rules
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
RET	Renewable Energy Target
RIT-T	Regulatory Investment Test for Transmission
TNSP	Transmission Network Service Provider
USE	Unserved Energy
VCR	Value of Customer Reliability

1. Introduction

This PSCR represents the first step in the application of the RIT-T to address the risk of transformer bushing failure on the South Australian transmission network.

This report:

- describes the identified need which we are seeking to address, together with the assumptions used in identifying this need;
- sets out the technical characteristics that a network support option would be required to deliver to address this identified need;
- outlines the credible options we consider address the identified need;
- discusses specific categories of market benefit that, in the case of this RIT-T assessment, are unlikely to be material;
- presents the results of our economic assessment of the credible options and identifies the preferred option and the reasons for the preferred option; and
- sets out our basis for exemption from a Project Assessment Draft Report (PADR).

1.1 Why we consider this RIT-T is necessary

Changes to the National Electricity Rules (NER) in July 2017 extended the application of the RIT-T to replacement capital expenditure commencing from 18 September 2017[3].

Accordingly, we have initiated this RIT-T to consult on proposed expenditure related to replacing transformer bushings, as none of the exemptions listed in NER clause 5.16.3(a) apply.

The credible options discussed in this PSCR have not been foreshadowed in AEMO's National Transmission Network Development Plan (NTNDP) or Integrated System Plan as they do not play a part in the main transmission flow paths between the NEM regions.

1.2 Submissions and next steps

We welcome written submissions on this PSCR. Submissions are due on or before 14 November 2018. Submissions should be emailed to consultation@electranet.com.au.

Submissions will be published on the ElectraNet website. If you do not want your submission to be made publicly available, please clearly specify this at the time of lodging your submission.

Subject to submissions received on this PSCR, a Project Assessment Conclusions Report (PACR) is expected to be published by December 2018.

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3 The application of the RIT-T to replacement expenditure ('repex') commenced on 18 September 2017, however, all repex projects that were 'committed' by 30 January 2018 are exempt. See paragraph 18 of the AER's RIT-T for the definition of a 'committed project'. While the planning process for replacing the identified bushings is now well-advanced, the project is not yet 'committed'. Accordingly, we have initiated this RIT-T to consult on its proposed expenditure related to replacing these bushings.

Further details in relation to this project can be obtained from:

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2. The identified need for this RIT-T is to ensure reliable and safe supply of electricity to South Australia

This section outlines the identified need for this RIT-T, as well as the assumptions underpinning it. It first provides some background on the identified bushings and their role in the wider transmission of electricity in South Australia.

2.1 Background to the identified need

Bushings are insulated devices that allow an electrical conductor to pass safely through a grounded conducting barrier such as the case of a transformer or circuit breaker. Bushings have traditionally been made from porcelain, although other materials are now used such as polymers, which have lower risks of exploding (and lower consequential damage if they do explode).

Figure 2 illustrates bushings on a transformer at the Para substation. An example of a transformer bushing is highlighted below.

Figure 2 – Bushings on Para #2 transformer

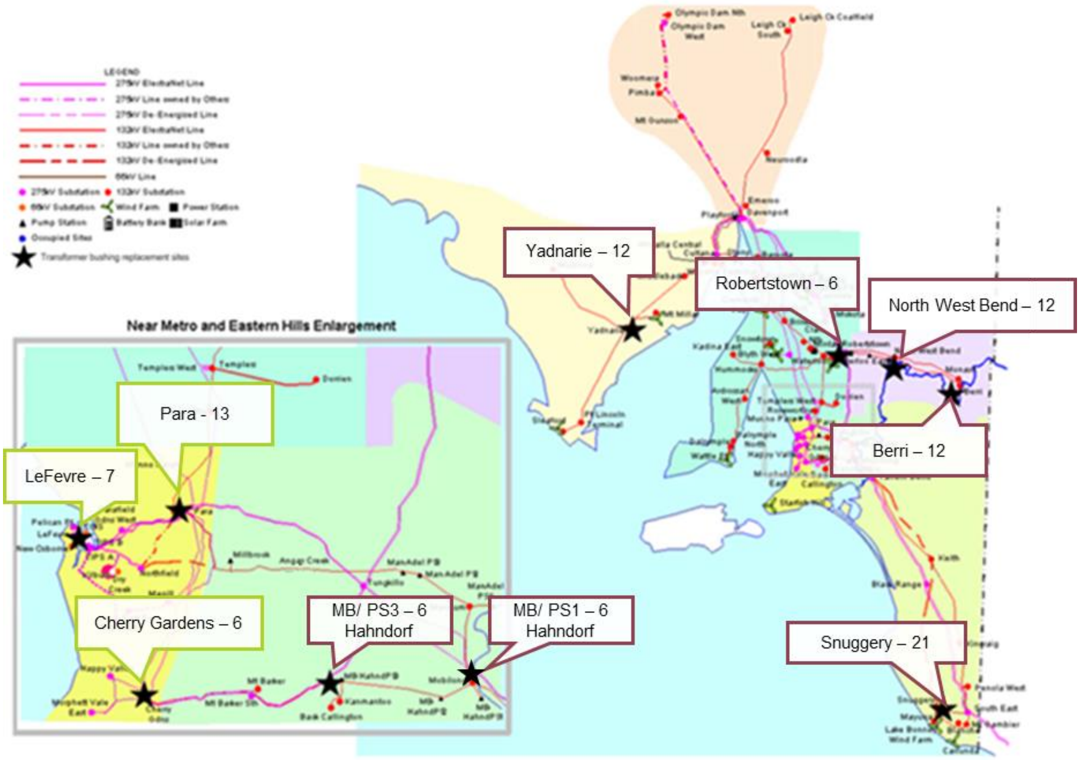
Transformer bushings are essential to the task of transmitting electricity. Without them, transformers, and hence substations, cannot adjust the electrical voltage for efficient electrical power transportation to transmission and distribution customers.

We have identified 101 bushings fitted on 18 power transformers across the transmission network that are now reaching, or past, the end of their technical lives and require

replacement based on their condition. These bushings have a standard technical life[4] of 40 years and are now aged between 36 and 55 years old. The identified transformer bushings are located at the following ten substations:

- Metropolitan substations – Para, Cherry Gardens and LeFevre; and
- Rural substations – Robertstown, Snuggery, Yadnarie, Murray Bridge/ Hahndorf Pump Station 1 (Murray Bridge/ Hahndorf PS1), Murray Bridge/ Hahndorf Pump Station 3 (Murray Bridge/ Hahndorf PS3), Berri and North West Bend. [5]

Figure 3 – Location of the transformer bushings that require replacing



The figure above illustrates the distribution of the ten substations with bushings that require replacement (green denotes metropolitan substations, while red denotes rural substations). It also illustrates how many bushings require replacement at each substation.

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4 The AER considers that repex involves replacing an asset or asset component with its modern equivalent where the asset has reached the end of its *economic* life, which takes into account the age, condition, technology and operating environment of an existing asset (see: AER, *ElectraNet transmission determination 2018 to 2023*, Attachment 6 – Capital expenditure, Draft Decision, October 2017, p. 42.). We present here the standard technical lives of the bushings for context and note that the assessment of replacing the identified bushings, both in the Revenue Proposal and this RIT-T, is consistent with the concept of economic life; i.e. the expenditure decision is primarily based on the existing asset's inability to efficiently maintain its service performance requirement.

5 While there are more than 101 transformer bushings in ElectraNet's network that are now reaching, or past, the end of their technical lives, these additional bushings have either been assessed as not requiring replacement due to their condition or will be replaced as part of a separate transformer replacement project. This RIT-T relates to the 101 transformer bushings on 18 different transformers located across 10 different substations which are not otherwise scheduled to be replaced as part of a wider augmentation or rebuild in the 2018-2023 regulatory control period.

All substations serve a range of electricity customers via SA Power Networks' distribution network, except for the 'Murray Bridge/ Hahndorf PS1' and 'Murray Bridge/ Hahndorf PS3' substations, which solely serve SA Water pump stations (i.e. a direct connect customer). In addition, the transformers at Cherry Gardens and Robertstown with bushings that require replacing are 'tie transformers'; i.e. they act to facilitate the transfer of electrical power between two different transmission-level voltages and do not step-down to the distribution network.

In total, we have identified for replacement 26 transformer bushings fitted on 4 power transformers in metropolitan areas and 75 transformer bushings fitted on 14 power transformers in rural areas.

The identified bushings cover at a minimum one transformer at each substation and, in many cases, all transformers at the substation. The table below summarises the distribution of the identified bushings across the transformers at each substation.

Table 2 - Number of affected transformers at each substation

Substation	Transformers	Number of identified bushings
Para	TF1 – 120 MVA	6 Bushings
	TF2 – 120 MVA	7 Bushings
Cherry Gardens	TF1 – 160 MVA	6 Bushings
Robertstown	TF1 – 160 MVA	6 Bushings
LeFevre	TF5 – 180 MVA	7 Bushings
Snuggery *	TF1 – 25 MVA	7 Bushings
	TF2 – 25 MVA	7 Bushings
	TF3 – 25 MVA	7 Bushings
Yadnarie	TF1 – 20 MVA	6 Bushings
	TF2 – 20 MVA	6 Bushings
MB/Hahndorf PS1	TF1 – 16.5 MVA	3 Bushings
	TF2 – 16.5 MVA	3 Bushings
MB/Hahndorf PS3	TF1 – 16.5 MVA	3 Bushings
	TF2 – 16.5 MVA	3 Bushings
Berri	TF1 – 65 MVA	6 Bushings
	TF2 – 65 MVA	6 Bushings
North West Bend	TF1 – 20 MVA	6 Bushings
	TF2 – 20 MVA	6 Bushings

* Snuggery has 3x25 MVA transformers serving industrial load and 1x25 MVA transformer serving rural load. The transformers selected for bushing replacement serve the industrial loads.

If the identified bushings remain in service, it is likely that a number of these assets will fail during the next 5-10 years, which may result in unplanned outages on parts of the network.

If a transformer bushing fails, the affected transformer can experience an oil-fuelled fire, which causes consequential damage to the transformer and other equipment, as well as safety risk to network personnel and the wider community, and, in a severe scenario,

unserved energy for electricity customers because of the transformer itself completely failing.

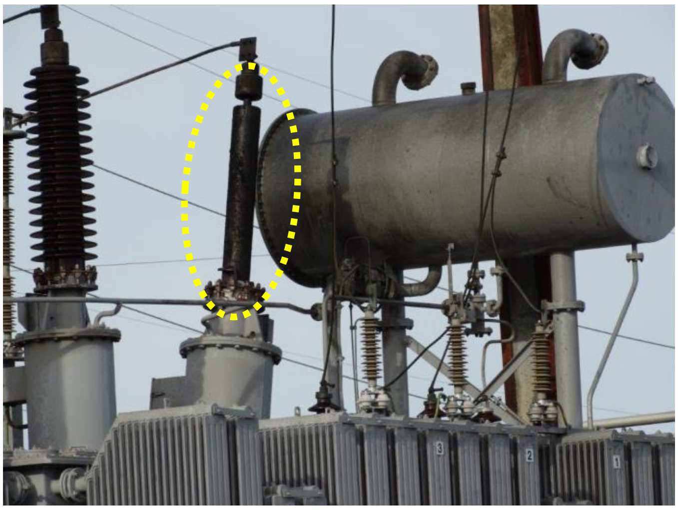
Relevantly, on 3 August 2018, one of the 132 kV transformer bushings on transformer number 3 at the Snuggery substation suffered an explosive failure. That bushing was one of those identified as requiring replacement as part of this assessment.

The explosive bushing failure at Snuggery substation occurred in the evening while no personnel were on site. On this occasion, it does not appear that the explosive failure resulted in significant collateral damage to the transformer or to other major equipment adjacent to it.

Consequently, there were no injuries to personnel and there was no loss of load as a result of the explosive failure of the bushing. However, due to the fragmentation of the exploded bushing and the debris radius, thorough checks of the substation for collateral damage are required and are yet to be completed at this time.

The figure below illustrates the appearance of transformer number 3 at the Snuggery substation after the explosive failure of one of its 132 kV bushings. The location of the failed bushing on the transformer showing the outer porcelain housing missing is highlighted in Figure 4 below. An intact bushing can be seen to the left hand side of the failed item.

Figure 4 – Appearance of Snuggery substation transformer number 3 after explosive bushing failure



2.2 Description of the identified need for this RIT-T

The identified need for this project is to manage the risk of failure of individual transformer bushings that are reaching, or have past, the end of their technical lives based on their condition.

We assess the condition of, and timing of ultimate replacement for, transformer bushings as part of our ongoing asset management processes. There is an increased likelihood that a number of these assets will fail within the next 5-10 years, resulting in the unplanned unavailability of parts of the network.

We have classified this RIT-T as a market benefits driven RIT-T because, while the aim is to maintain the quality, reliability and security of supply of prescribed transmission services, the economic assessment is not driven by on the requirement to meet a mandated reliability standard. Rather a full cost benefit assessment has been undertaken, comparing the risk cost reduction benefits of asset replacement options with the cost of those options.

2.3 Assumptions underpinning the identified need

This section summarises the key assumptions from the risk cost modelling and other key assumptions that underpin the identified need for this RIT-T. Section 6 provides further detail on the general modelling approaches applied, including additional detail on the risk cost modelling framework.

For the purposes of this assessment, the risk cost model focuses on a single mode of failure, an explosive failure of a transformer bushing, due to the potential for wide-ranging consequences including unserved energy, collateral equipment damage and personal injury and environmental costs as explained in section 2.3.2.

Assumptions relevant to the risk cost model are discussed in section 2.3.1 – 2.3.3. Corrective and routine maintenance assumptions are discussed in section 2.3.4.

2.3.1 The probability of transformer bushings failing

The probability of bushing failure is estimated by considering historical data, manufacturers' specifications, and industry research and experience.

The risk cost model assumes that one transformer bushing will suffer an explosive failure over the next 6 years (corresponding to an annual explosive failure rate of 0.17 per cent). The failure rate is assumed to increase progressively from year 7.

2.3.2 The adverse effects resulting from any bushings failure

The potential adverse consequences resulting from the occurrence of a bushing failure include electricity service interruption, bushfire, personal injury, repair cost, service level breaches and environmental damage. When a transformer bushing fails, the affected transformer can experience an oil-fuelled fire, which causes consequential damage to the transformer and other equipment. In a severe scenario, the failed bushing can result in unserved energy for electricity customers because of the transformer itself completely failing.

Explosive bushing failures can also result in projectiles and oil spills, which present a safety risk to those in the immediate, or potentially wider area. The failure of critical transformers can result in additional costs associated with asset replacement and repair, collateral damage to other plant/equipment, and costs associated with injuries/fatalities to those surrounding the incident.

Our risk cost model defines the following effects that could occur from a transformer bushing failure:

- Unserved energy to electricity customers during the time taken to:

- restore (or replace) the transformer(s); and
- isolate the affected substation to control any explosion and fire

- Costs associated with having to repair (or replace) damaged transformers, bushings and other equipment;
- Personal injury costs associated with explosive failures; and
- Environmental costs associated with oil leaks, fire start etc.

2.3.3 The likelihood and cost of negative consequences of bushing failure

Our risk cost model individually defines a set of assumptions for the adverse effects described above, which allows the 'likelihood of consequence' (LoC) and 'cost of consequence' (CoC) to be estimated for transformer bushing failures.

The costs associated with service interruption and asset replacement account for more than 80 per cent of the total risk cost resulting from transformer bushing failure in this assessment. Service interruption includes both the unserved energy resulting from the loss of the affected transformer and additional costs associated with isolating the affected substation for a period to control any explosion and fire.

The risk cost model defines a load estimate and outage duration specific for metropolitan and rural transformers. Implicit for service interruption events are load loss estimates that are based on historical consumption information and connection point demand forecasts.

Outage durations for affected transformers are based on the typical time to change out and commission a new transformer. Outage durations of isolated substations are based on the estimated time for an emergency crew to respond to the site and assess and make safe collateral damage to adjacent plant.

For bushing failures at metropolitan substations relevant to this assessment, it is assumed to be possible to maintain supply via the underlying 66 kV distribution network. Therefore, unserved energy resulting from an explosive transformer bushing failure that damages multiple transformers at a metropolitan substation is assumed to be zero. For the same reason, unserved energy resulting from isolation of two of the three metropolitan substations, Para and Cherry Gardens, to control fire is also assumed to be zero.

The third metropolitan substation, LeFevre, provides supply to the local 66/11 kV substation as well as the western suburbs 66 kV transmission network. The unavailability of the 66/11 kV substation would result in an interruption to the supply of some local load which cannot be supplied from other substations. Therefore, for an explosive bushing failure at the LeFevre substation, we assume a 50% probability that supply of 6 MW[6] of load is interrupted for 8 hours when isolating the substation to control an explosion and fire.

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6 Based on zone substation data published by SA Power Networks, available at https://www.sapowernetworks.com.au/centric/industry/our_network/zone_substation_data_v1.jsp.

When estimating costs associated with service interruption for rural transformers, the likelihood that an explosive transformer bushing failure would cause damage to multiple transformers that results in the loss of all load supplied from the substation is assumed to be 1%. The interruption to supply is assumed to be 5.9 MW[7] of mixed load for 8 days to allow for transformer replacement works. We also assume a 50% probability that 7.4 MW[8] of load is interrupted for 8 hours when isolating rural substations to control an explosion and fire.

For both metropolitan and rural substations, we assume a 50% probability that an explosive transformer bushing failure will result in transformer replacement.

These assumptions were revised to take into the account the recent explosive bushing failure at Snuggery substation. In particular, the assumed probability of load loss and transformer replacement as a result of an explosive bushing failure was reduced.

The cost of consequence for all service interruptions is valued at approximately $36,000/MWh, based on the relevant Value of Customer Reliability (VCR) escalated to 2017/18 dollars (as described in section 5.1).

2.3.4 Corrective and routine maintenance assumptions

Corrective and routine maintenance costs are estimated independently of the risk cost modelling framework.

Corrective maintenance estimates take into account all transformer bushing failure modes other than explosive failure (which is captured by the risk cost model). It is assumed that of the bushings identified as requiring replacement in this assessment, 5% will require replacement annually, either as emergency corrective maintenance or in response to condition tests. Corrective maintenance estimates include costs associated with emergency replacement, unserved energy and the deferral of other works due to asset access, loss of redundancy and the redeployment of resources.

Routine maintenance consists of periodic transformer bushing tests. The costs of this testing program are reduced once a credible option is implemented when compared with the base case because the maintenance schedule is reset upon replacement of an asset.

3. Potential credible options to address the identified need

The analysis has identified that there is only one technically feasible option, which is to replace the end-of-life transformer bushings on a like-for-like basis. This is because bushings play a very specific role in enabling transformers to operate and, without them, transformers, and hence substations, cannot fulfil their role of transforming the electrical voltage for efficient electrical power transportation to transmission and distribution connected electricity customers.

We have investigated two credible options with different timing for the proposed program:

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7 5.9 MW is the estimated average load loss over 8 days for the rural substations identified in this assessment.

8 Initial load loss at rural substations is assumed to be 100% of the substation load. The transfer of feeders to other connection points allows some load to be restored at certain rural substations. Therefore, the average initial load loss at rural transformers (7.4 MW) is greater than the average load loss over 8 days (5.9 MW).

- Option 1 – Replace transformer bushings between 2018-19 and 2021-2022; and
- Option 2 – Defer replacement of the transformer bushings to 2023-24 to 2026-27.

Option 2 has a lower cost, in present value terms, than Option 1 but it comes with a higher expected risk associated with keeping the identified bushings in-service for an additional five years.

Both Option 1 and Option 2 are considered to be technically and economically feasible and able to be implemented in sufficient time to meet the identified need.[9] In addition, all works under these options are assumed to be completed in accordance with the relevant standards, with bushings being replaced with minimal modification to fit to the power transformers.

3.1 Option 1 – Replace transformer bushings by 2021-22

Option 1 involves replacing the identified bushings in the 2018-2023 regulatory control period and replacing the relevant bushings as fitted to each affected transformer across the 10 substation sites in-turn.

The existing bushings would be replaced with a newer technology, which uses polymer instead of porcelain. Polymer bushings have a lower risk of exploding when they fail than porcelain bushings and, if they do explode, the risk of consequential damage and injury is contained and far lower.

The estimated capital cost of this option is approximately $6.86 million. Routine operating and maintenance costs for bushing tests are approximately $95,000/annum.

It is estimated that the construction time for each transformer is around 8 weeks; i.e. around 2.5 to 3 years in total. We estimate that all bushings could be replaced and commissioned by 2021-22 under this option.

3.2 Option 2 – Defer replacement of the identified bushings by five years

Option 2 is a deferred version of Option 1 and involves replacing the identified bushings in the 2023-2028 regulatory control period.

The scope, estimated cost and construction time remains the same as for Option 1. We estimate that all bushings could be replaced and commissioned by 2026-27 under this option.

3.3 Options considered but not progressed

We have also considered whether there are other credible options that would meet the identified need. However, the identified need to address end-of-life bushings on transformers does not lend itself to any solution other than to replace the bushings as the only technically and economically feasible option given the unique and specific function of these assets. Consequently, we have not identified other feasible options.

9 In accordance with the requirements of NER clause 5.15.2(a).

One conceivable option, for example, would be to replace the entire power transformer at each site, as opposed to just the bushings. However, the capital cost of this option is expected to be in the order of $27-63 million (i.e. $1.5-3.5 million per transformer), which is significantly more than the option outlined above and does not provide any additional market benefits. In addition, the condition of other transformer assets is such that they do not require replacing in coming years. Therefore, this is not considered to be an economically feasible option.

In addition, as set out in section 4 below, we do not consider that network support solutions can address, or help address, the identified need.

3.4 There is not expected to be a material inter-network impact

We have considered whether the two credible options are expected to have a material inter-regional impact.[10]

By reference to AEMO's screening test for an inter-network impact[11], neither credible option involves a series capacitor or modification near an existing series capacitor.

Neither of the options are expected to result in change in power transfer capability between South Australia and neighbouring transmission networks.

In addition, fault levels are not expected to increase at any substation in another TNSP's network. Therefore, there are no material inter-network impacts associated with Option 1 or Option 2.

4. Required technical characteristics of network support options

We do not consider that network support solutions can assist with meeting the identified need for this RIT-T. This is driven by the unique and specific role that the identified bushings play in the transmission of electricity, as well as their relatively low replacement cost (i.e. $68,000 each, or $6.86 million in total to replace all 101 identified bushings).

Notwithstanding, this section sets out the required technical characteristics for a network support option for completeness, consistent with the requirements of the RIT-T.

4.1 Required technical characteristics for a network support option

As outlined in section 2, transformer bushings are required for the operation of transformers. Without bushings, a transformer and, consequently, a substation would not be able to function.

A network support option that avoids replacement of transformer bushings would therefore need to replicate the functionality, capacity and reliability of the entire transformer substation on an enduring basis at a cost that is lower than the network option currently

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10 In accordance with NER clause 5.16.4(b)(6)(ii).

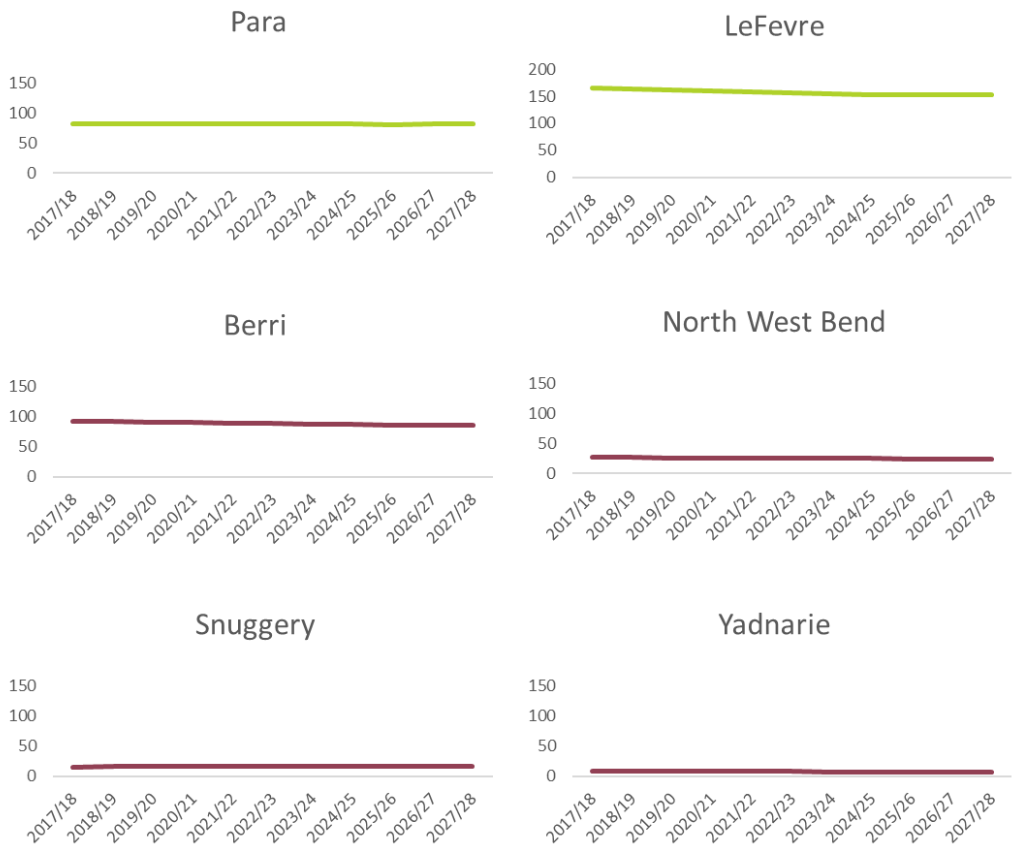
11 AEMO's suggested screening test for a material inter-network impact is set out in Appendix 3 of the Inter-Regional Planning Committee's Final Determination: Criteria for Assessing Material Inter-Network Impact of Transmission Augmentations, Version 1.3, October 2004.

under consideration. The capital cost of replacing the bushings is approximately $686,000 *per substation*.

Figure 5 sets out a ten-year forecast of load for each of the six affected substations that serve electricity customers via the distribution network, ie:

- Metropolitan substations – Para and LeFevre
- Rural substations – Snuggery, Yadnarie, Berri and North West Bend.

Figure 5 - Forecast load (MW) at affected substations serving distribution-level customers



Green denotes metropolitan substations, while red denotes rural substations.

Source: ElectraNet, South Australian Connection Point Demand Forecasts, May 2017. Load forecasts for Para and LeFevre have been derived from the aggregated Northern Suburbs and Western Suburbs forecasts, respectively (specifically, by pro-rating installed transformer capacities to total Northern Suburbs transformer capacity and total installed Western Suburbs transformer capacity). ElectraNet's 2018 South Australian Connection Point Forecast was published on 29 June 2018, however, the relevant load forecasts have not materially changed.

A network support option would be required to meet or offset these loads in full on a continuous basis, 24 hours a day over a period of years. While network support options involving generation may be technically possible, such a solution at the scale required is unlikely to be economically feasible.

In terms of the other substations that have transformer bushings identified for replacement, we note that Cherry Gardens and Robertstown are 'tie transformers', which

facilitate the transfer of electrical power between two different transmission-level voltages and do not step-down to the distribution network. It is therefore not expected that network support solutions could offer a feasible alternative to the role that these transformers play in the wider task of transmitting electricity in South Australia.

The ‘Murray Bridge/ Hahndorf PS1’ and ‘Murray Bridge/ Hahndorf PS3’ substations solely serve SA Water pump stations (i.e. a direct connect customer). The current peak demand for each of these sites is approximately 7 MW and 10 MW per annum, respectively.

In addition, all substations serving distribution exit points (i.e. all substations except those with ‘tie transformers’ as well as the dedicated SA Water substations) are classified as ‘Category 4’ under the Electricity Transmission Code (ETC),[12] except for Yadnarie, which is classified as ‘Category 2’. These categories impose a range of reliability standards for these substations, including:[13]

- both categories require that there is “N-1” equivalent transformer capacity for at least 100 per cent of contracted agreed maximum demand; and
- in the event of an interruption arising from the failure of a transformer or network support arrangements, we must use our best endeavours to restore at least “N” equivalent transformer capacity within 12 hours of the commencement of the interruption for Category 4 and within 8 days for Category 2.

Any network support solution seeking to remove the need for any of the affected transformers would therefore need to ensure ongoing compliance with the applicable reliability standards in accordance with the ETC.

5. Materiality of market benefits for this RIT-T assessment

The section outlines the categories of market benefits prescribed in the NER and whether they are considered material for this RIT-T.[14]

The bulk of the benefits associated with each of the options considered in this assessment are captured in the costs avoided by each of the options. As described above, these include avoided corrective maintenance costs, avoided routine maintenance costs (i.e. deferred routine bushing tests) and avoided risk costs.

Of these avoided costs, only unserved energy through involuntary load shedding is considered a market benefit category under the Rules, as discussed further below.

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12 There are four transformers at Snuggery; three that serve industrial load (and are Category 4) and one that serves rural load (and is Category 3).

13 ETC clauses 2.6 & 2.8.

14 The NER requires that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific category (or categories) is unlikely to be material in relation to the RIT-T assessment for a specific option – NER clause 5.16.1(c)(6). Under NER clause 5.16.4(b)(6)(iii), the PSCR should set out the classes of market benefit that the RIT-T proponent considers are not likely to be material for a particular RIT-T assessment.

5.1 Avoided involuntary load shedding is the only relevant market benefit

We consider that the only relevant market benefit for this RIT-T relates to changes in involuntary load shedding. The expected unserved energy under the base case has been estimated as part of our risk cost modelling framework, which is avoided under both the credible options. The difference between Options 1 and 2 is that Option 1 allows this expected unserved energy to be substantially reduced compared with Option 2.

The benefit associated with the reduction in unserved energy is valued using VCR, expressed in $/MWh. A VCR measure estimates the value customers place on having reliable electricity supplies. The risk cost modelling has applied a VCR value of approximately $36,000/MWh, which has been sourced from AEMO's 2014 Value of Customer Reliability Review,[15] and represents an aggregate VCR (including customers directly connected to the transmission network) for South Australia.

5.2 Market benefits relating to the wholesale market are not material

The Australian Energy Regulator (AER) has recognised that if the credible options considered will not have an impact on the wholesale market, then a number of classes of market benefits will not be material in the RIT-T assessment, and so do not need to be estimated.[16]

Neither credible option addresses network constraints between competing generating centres and are therefore not expected to result in any change in dispatch outcomes and wholesale market prices.

We therefore consider that the following classes of market benefits are not material for this RIT-T assessment for Option 1 and Option 2:

- changes in fuel consumption arising through different patterns of generation dispatch;
- changes in voluntary load curtailment (since there is no impact on pool price);
- changes in costs for parties, other than for ElectraNet (since there will be no deferral of generation investment);
- changes in ancillary services costs;
- competition benefits; and
- Renewable Energy Target (RET) penalties.

5.3 Other classes of market benefits are not expected to be material

In addition to the classes of market benefits listed above, NER clause 5.16.1(c)(4) requires us to consider the following classes of market benefits in relation to each credible option: differences in the timing of transmission investment; option value; and changes in network losses.

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15 AEMO, *Value of Customer Reliability Review for South Australia*, September 2014, p. 31 and p. 40.

16 AER, *Final Regulatory Investment Test for Transmission Application Guidelines*, 18 September 2017, pp. 13-14.

We consider that none of the four classes of market benefits listed above are material for this RIT-T assessment for the reasons set out below. We do not consider that there are any other classes of market benefits, which are material for the purposes of this RIT-T assessment.

Table 3 - Reasons why non-wholesale market benefit categories are considered immaterial

Market benefit category	Reason(s) why it is considered immaterial
Differences in the timing of transmission investment	Neither credible option will affect the timing of other unrelated transmission investments (i.e. transmission investments based on a need that falls outside the scope of that described in section 2). Consequently, the market benefits associated with differences in the timing of unrelated transmission investment are not material to the RIT-T assessment.
Option value	The AER has stated that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change and the credible options considered by the TNSP are sufficiently flexible to respond to that change.[17] None of these conditions apply to the present assessment. The AER has also stated the view that appropriate identification of credible options and reasonable scenarios captures any option value, thereby meeting the NER requirement to consider option value as a class of market benefit under the RIT-T. Changes in future demand levels are not relevant for this RIT-T, since the need for and timing of the required investment is being driven by asset condition rather than future demand growth. As a result, it is not relevant to consider different future demand scenarios in undertaking the RIT-T analysis.
Changes in network losses	Given both credible options maintain the same network capacity as current at the same location, there are not expected to be any differences in network losses.

6. Description of the modelling methodologies applied

This section outlines the methodologies and assumptions we have applied to undertake this RIT-T assessment.

6.1 Overview of the risk cost modelling framework

We have applied an asset 'risk cost' evaluation framework to quantify the risk cost reductions associated with asset replacement and refurbishment projects that are primarily focused on mitigating risk as input to economic evaluation and options analysis.

The 'risk cost reductions' have been calculated as the product of:

- probability of failure (PoF) of an asset, which is the probability of a failure occurring based on asset failure history information and industry data;
- likelihood of consequence (LoC), which is the likelihood of an adverse consequence of the failure event based on historical information and statistical factors and assumptions; and
- cost of consequence (CoC), which is the estimated cost of the adverse consequence based on modelled assumptions.

[17] AER, *Final Regulatory Investment Test for Transmission Application Guidelines*, 18 September 2017, pp. 37 & 74.

These three variables allow the expected risk cost benefits to be quantified and an assessment against the cost of doing so to be undertaken. Avoided risk cost values are the difference between risk costs incurred under the base case and respective options.

The approach we applied to quantifying risk was presented as part of our Revenue Proposal for the 2018-2023 regulatory control period. The AER has reported it to be consistent with good industry practice and to generally reflect reasonable inputs and assumptions.[18]

More detail on the key inputs and assumptions made for individual asset risk cost evaluations can be found in ElectraNet's asset risk cost modelling guideline.[19]

6.2 The discount rate and assessment period

The RIT-T analysis has been undertaken over a 20-year period from 2018 to 2037, which considers the size, complexity and expected life of each option to provide a reasonable indication of its cost.

While the transformer bushings have asset lives greater than 20 years, we have taken a terminal value approach to incorporating capital costs in the assessment, which ensures that the capital cost of each option is appropriately captured in the 20-year assessment period.

We have adopted a real, pre-tax discount rate of 6 per cent as the central assumption for the NPV analysis presented in this report. We consider that this is a reasonable contemporary approximation of a 'commercial' discount rate (a different concept to a regulatory WACC), consistent with the RIT-T.

The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated real, pre-tax weighted average cost of capital (WACC) be used as the lower bound discount rate in the sensitivity testing.[20]

We have therefore tested the sensitivity of the results to changes in this discount rate assumption, and specifically to the adoption of a lower bound discount rate of 3.62 per cent, and an upper bound discount rate of 8.38 per cent (i.e. a symmetrical adjustment upward).

6.3 Description of reasonable scenarios

The RIT-T analysis is required to incorporate a number of different reasonable scenarios, which are used to estimate expected net market benefits. The number and choice of reasonable scenarios must be appropriate to the credible options under consideration.

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18 AER, *ElectraNet transmission determination 2018 to 2023*, Draft Decision, Attachment 6 – Capital expenditure, October 2017, p. 4.

19 Available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/electranet-determination-2018-23/proposal#step-50979.

20 AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph 15, p. 7.

For a market benefits driven RIT-T such as this, the choice of reasonable scenarios must reflect any variables or parameters that are likely to affect the ranking of the credible options, or the sign of the net economic benefits of any of the credible options.[21]

We have developed three scenarios for this RIT-T assessment:

- a ‘central’ scenario reflecting our base set of key assumptions;
- a ‘low benefits’ scenario – reflecting a conservative set of assumptions, which represents a lower bound on reasonably expected potential market benefits that could be realised under each credible option; and
- a ‘high benefits’ scenario – reflecting an optimistic set of assumptions, which represents an upper bound on reasonably expected potential market benefits.

The table below summarises the key assumptions making up each scenario. We have applied equal weighting to each scenario; i.e. 1/3 each.

As shown in section 7 below, the two options are closely ranked in the ‘low benefits’ scenario and Option 1 is the preferred option in both the ‘central’ and ‘high benefits’ scenarios. Given there is no material evidence for assigning a higher probability for one scenario over another in this assessment, the scenarios are weighted equally.[22]

Table 4 - Summary of the three scenarios

Key variable/parameter	Low benefits scenario	Central scenario	High benefits scenario
Capital costs	130 per cent of capital cost estimate	Base estimate	70 per cent of capital cost estimate
Commercial discount rate[23]	8.38 per cent	6 per cent	3.62 per cent
Avoided ‘risk cost’ benefit	70 per cent of base estimates	Base estimates	130 per cent of base estimates
Deferred routine bushings tests	70 per cent of base estimates	Base estimates	130 per cent of base estimates
Avoided corrective maintenance	70 per cent of base estimates	Base estimates	130 per cent of base estimates

7. Assessment of the credible options

This section outlines the assessment we have undertaken of the two credible network options. Each option is compared against a base case ‘do nothing’ option.

7.1 Gross benefits for each credible option

The table below summarises the gross benefit estimated for each option relative to the ‘do nothing’ base case in present value terms. The gross market benefit for each option has been calculated for each of the three scenarios outlined in the section above.

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21 AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph 16, p. 7.

22 In accordance with paragraph 4(a) of the RIT-T.

23 Expressed on a real, pre-tax basis

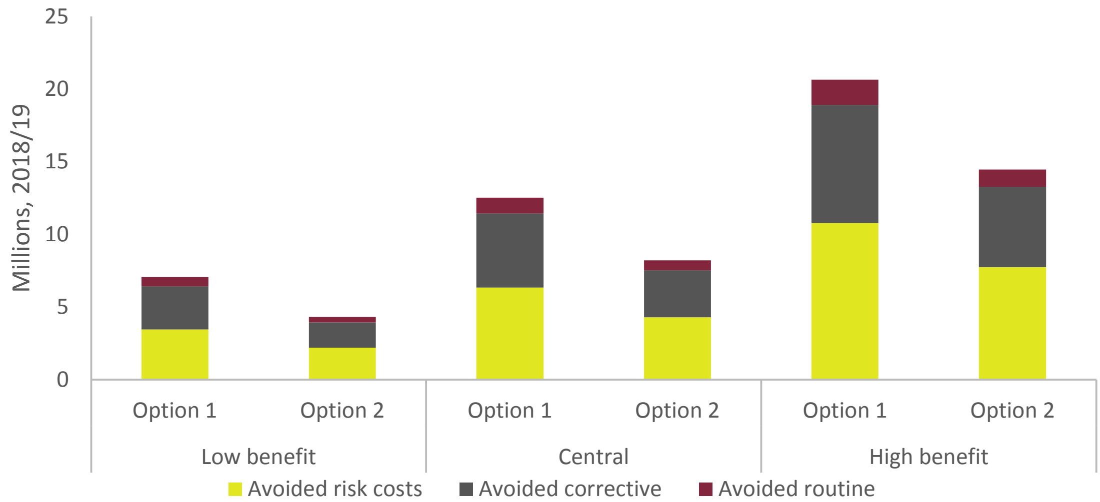
Table 5 Estimated gross market benefit for each option, PV $m

Option	Low benefits scenario	Central scenario	High benefits scenario
Option 1 – Replace transformer bushings by 2021-22	7.1	12.5	20.6
Option 2 – Defer replacement of bushings by five years	4.3	8.2	14.4

The figure below provides a breakdown of benefits relating to each credible option. The majority of the benefits for each option are derived from avoided risk of transformer bushing failure and avoided corrective maintenance. Avoided routine maintenance (i.e. deferred bushing tests) contribute relatively small amounts to gross benefits.

Option 1 has greater estimated gross benefits than Option 2 because the identified bushings are replaced approximately five years earlier than under Option 2. Most of the benefits are attributable to avoiding the risk costs of transformer bushing failure and avoided corrective maintenance, while avoided routine maintenance costs contribute relatively small amounts to the estimated benefits.

Figure 6 – Breakdown of present value gross economic benefits of Option 1 and Option 2



7.2 Estimated costs for each credible option

The table below summarises the costs of each credible option, relative to the base case, in present value terms. The cost of each option has been calculated for each of the three scenarios.

Table 6 - Estimated cost for each option, PV $m

Option	Low benefits scenario	Central scenario	High benefits scenario
Option 1 – Replace transformer bushings by 2021-22	-7.0	-5.5	-3.9
Option 2 – Defer replacement of bushings by five years	-4.1	-3.5	-2.6

While each option has the same cost in real terms in each scenario, Option 1 has a slightly higher cost in present value terms than Option 2 because of the identified bushings being replaced five years earlier than under Option 2.

7.3 Net present value assessment outcomes

The table below summaries the net market benefit in NPV terms for each credible option across the three scenarios, as well as on a weighted basis. The net market benefit is the gross benefits (as set out in section 7.1 above) minus the cost of each option (as outlined in section 7.2 above), all expressed in present value terms.

The table shows that Option 1 provides the greatest net economic benefit of the two options once the scenarios are probability-weighted, and that Option 1 provides positive market benefits across all scenarios.

Table 7 - Estimated net market benefit for each option, PV $m

Option	Low benefits scenario	Central scenario	High benefits scenario	Weighted
Option 1 – Replace transformer bushings by 2021-22	0.1	7.0	16.7	7.9
Option 2 – Defer replacement of bushings by five years	0.2	4.7	11.8	5.6

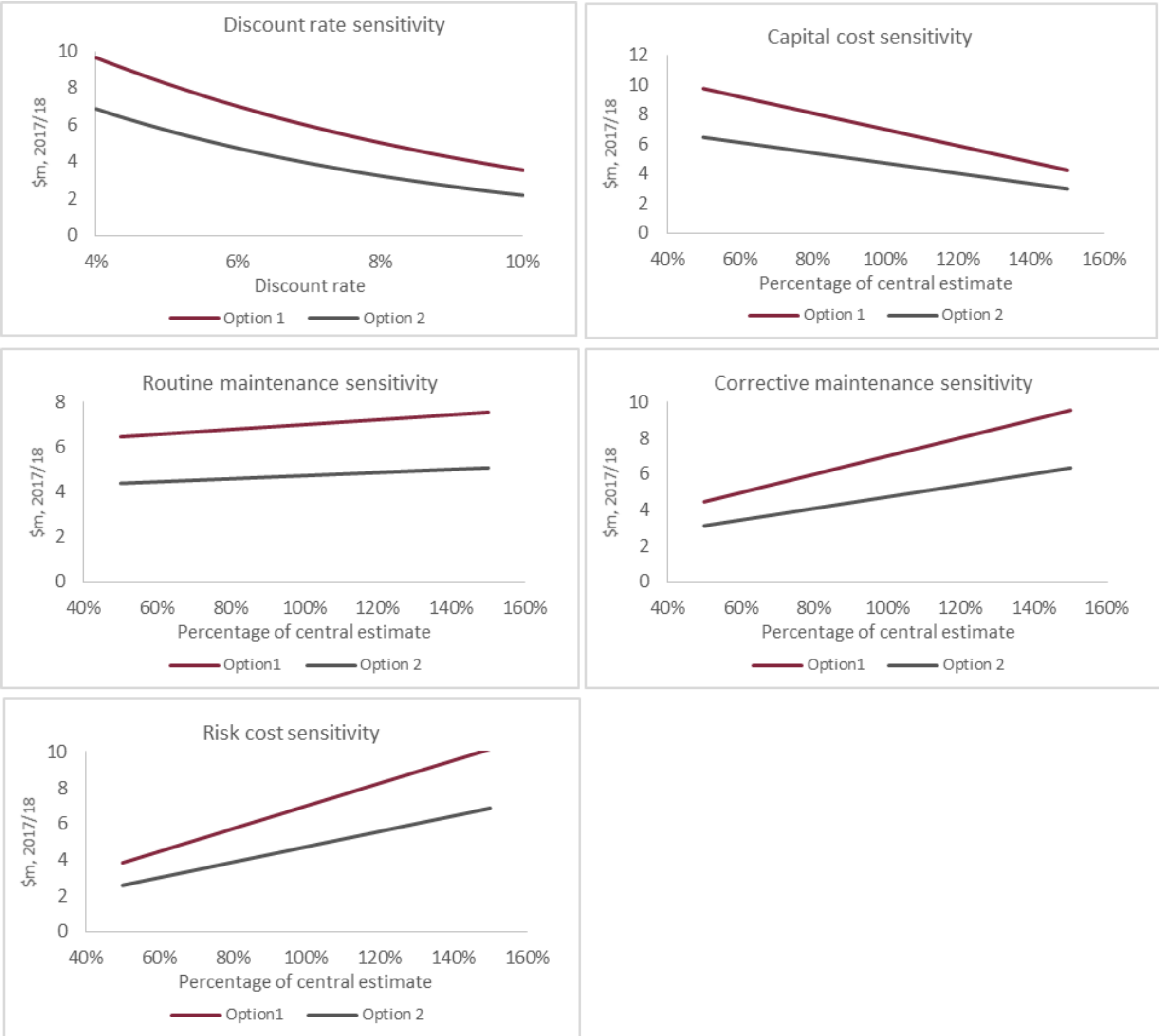
7.4 Sensitivity testing

We have undertaken a thorough sensitivity testing exercise to understand the robustness of the RIT-T assessment to underlying assumptions about key variables.

In particular, we have looked at the consequences for the credible options of 'getting it wrong' if the key underlying assumptions are not accurate. For example, sensitivity tests have been run on low and high avoided 'risk cost' benefits to ensure the robustness of the assessment. These tests investigate avoided aggregate risk cost benefits that are assumed to be 30 per cent higher and 30 per cent lower than avoided risk cost benefits estimated using the risk cost evaluation tool.

The five figures below illustrate the estimated net market benefits for each option if the five separate key assumptions in the central scenario are varied individually. Importantly, for all sensitivity tests shown below, the estimated net market benefit of Option 1 exceeds that for Option 2. Furthermore, the estimated net market benefits are found to be positive for both options over all sensitivities investigated.

Figure 7 – Sensitivity testing of the two credible options



8. Draft conclusion and exemption from preparing a Project Assessment Draft Report

The preferred option that has been identified in this assessment for addressing the identified need, as detailed in section 7, is Option 1; i.e. replacing transformer bushings by 2021 based on condition. This option is described in section 3 and is estimated to have a capital cost of $6.86 million.

Option 1 is the preferred option in accordance with NER clause 5.16.1(b) because it is the credible option that maximises the net present value of the net economic benefit to all those who produce, consume and transport electricity in the market.

NER clause 5.16.4(z1) provides for a TNSP to be exempt from producing a PADR for a RIT-T application, in the following circumstances:

- if the estimated capital cost of the preferred option is less than $41 million;
- if the TNSP identifies in its PSCR its proposed preferred option, together with its reasons for the preferred option and notes that the proposed investment has the benefit of the clause 5.16.4(z1) exemption; and
- if the TNSP considers that the proposed preferred option and any other credible options in respect of the identified need will not have a material market benefit for the classes of market benefit specified in clause 5.16.1(c)(4), except for market benefits arising from changes in voluntary and involuntary load shedding.

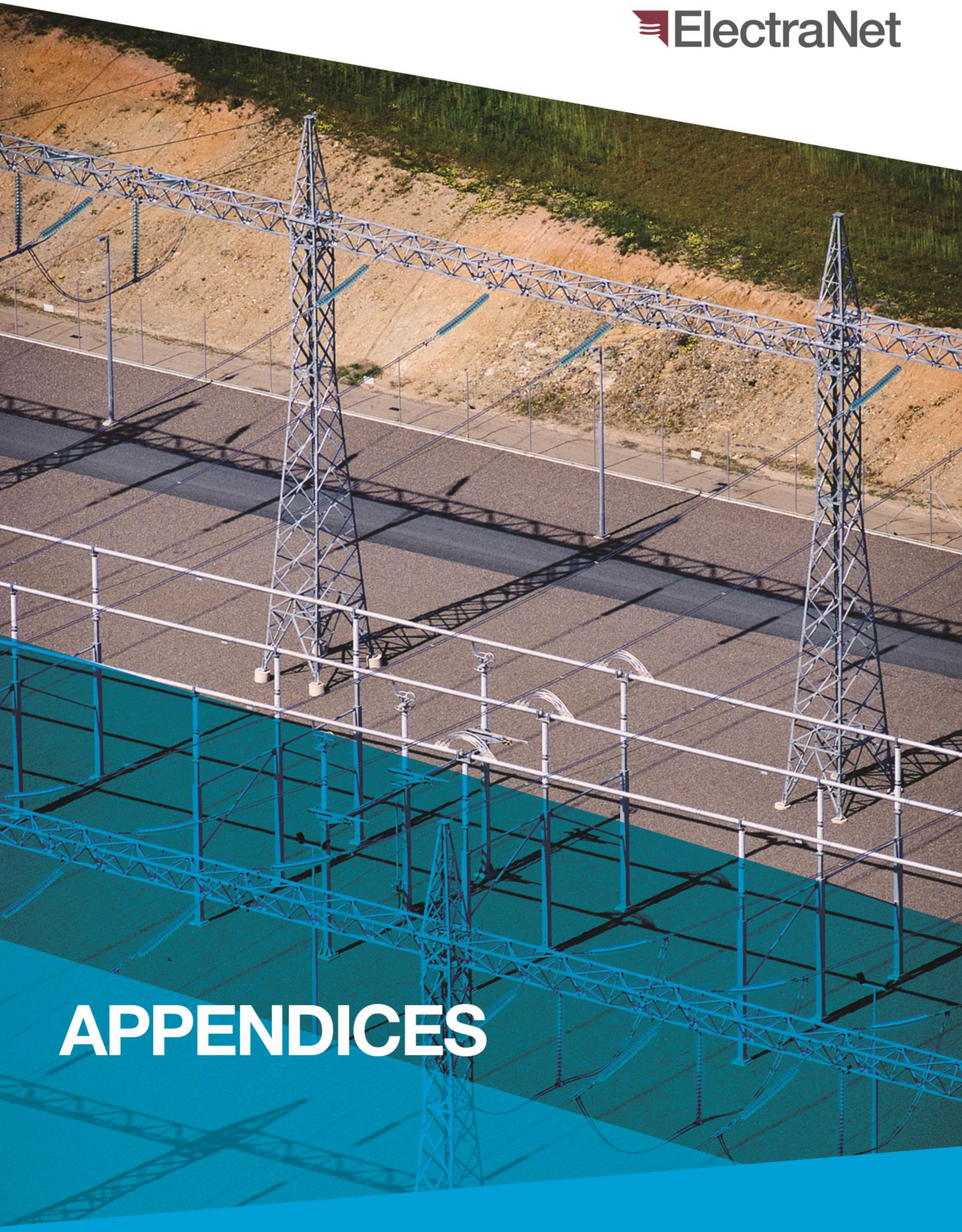
We consider that its investment in relation to Option 1 is exempt from producing a PADR under NER clause 5.16.4(z1) on the basis of meeting the criteria above.

In accordance with NER clause 5.16.4(z1)(4), the exemption from producing a PADR will no longer apply if we consider that an additional credible option that could deliver a material market benefit is identified during the consultation period.

Accordingly, if we consider that any additional credible options are identified, we will produce a PADR which includes an NPV assessment of the net market benefit of each additional credible option.

Should we consider that no additional credible options were identified during the consultation period, we intend to produce a PACR that addresses all submissions received during the consultation period including any issues in relation to the proposed preferred option.[24]

[24] In accordance with NER clause 5.16.4(z2).



APPENDICES

Appendix A Compliance checklist

This section sets out a compliance checklist which demonstrates the compliance of this PSCR with the requirements of clause 5.16.4(b) of the Rules version 109.

Rules clause	**Summary of requirements**	**Relevant section(s) in PSCR**
5.16.4 (b)	A RIT-T proponent must prepare a report (the project specification consultation report), which must include:	–
	(1) a description of the identified need;	2.2
	(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary);	2.3
	(3) the technical characteristics of the identified need that a non- network option would be required to deliver, such as: (i) the size of load reduction of additional supply; (ii) location; and (iii) operating profile;	4
	(4) if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent National Transmission Network Development Plan;	1.1
	(5) a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alterative transmission options, interconnectors, generation, demand side management, market network services or other network options;	3
	(6) for each credible option identified in accordance with subparagraph (5), information about: (i) the technical characteristics of the credible option; (ii) whether the credible option is reasonably likely to have a material inter-network impact; (iii) the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.16.1(c)(6), together with reasons of why the RIT-T proponent considers that these classes of market benefit are not likely to be material; (iv) the estimated construction timetable and commissioning date; and (v) to the extent practicable, the total indicative capital and operating and maintenance costs.	3 & 5

Rules clause	Summary of requirements	Relevant section(s) in PSCR
5.16.4(z1)	A RIT-T proponent is exempt from paragraphs (j) to (s) if: 1. the estimated capital cost of the proposed preferred option is less than $35 million (as varied in accordance with a cost threshold determination); 2. the relevant Network Service Provider has identified in its project specification consultation report: (i) its proposed preferred option; (ii) its reasons for the proposed preferred option; and (iii) that its RIT-T project has the benefit of this exemption; 3. the RIT-T proponent considers, in accordance with clause 5.16.1(c)(6), that the proposed preferred option and any other credible option in respect of the identified need will not have a material market benefit for the classes of market benefit specified in clause 5.16.1(c)(4) except those classes specified in clauses 5.16.1(c)(4)(ii) and (iii), and has stated this in its project specification consultation report; and 4. the RIT-T proponent forms the view that no submissions were received on the project specification consultation report which identified additional credible options that could deliver a material market benefit.	8

Appendix B Definitions

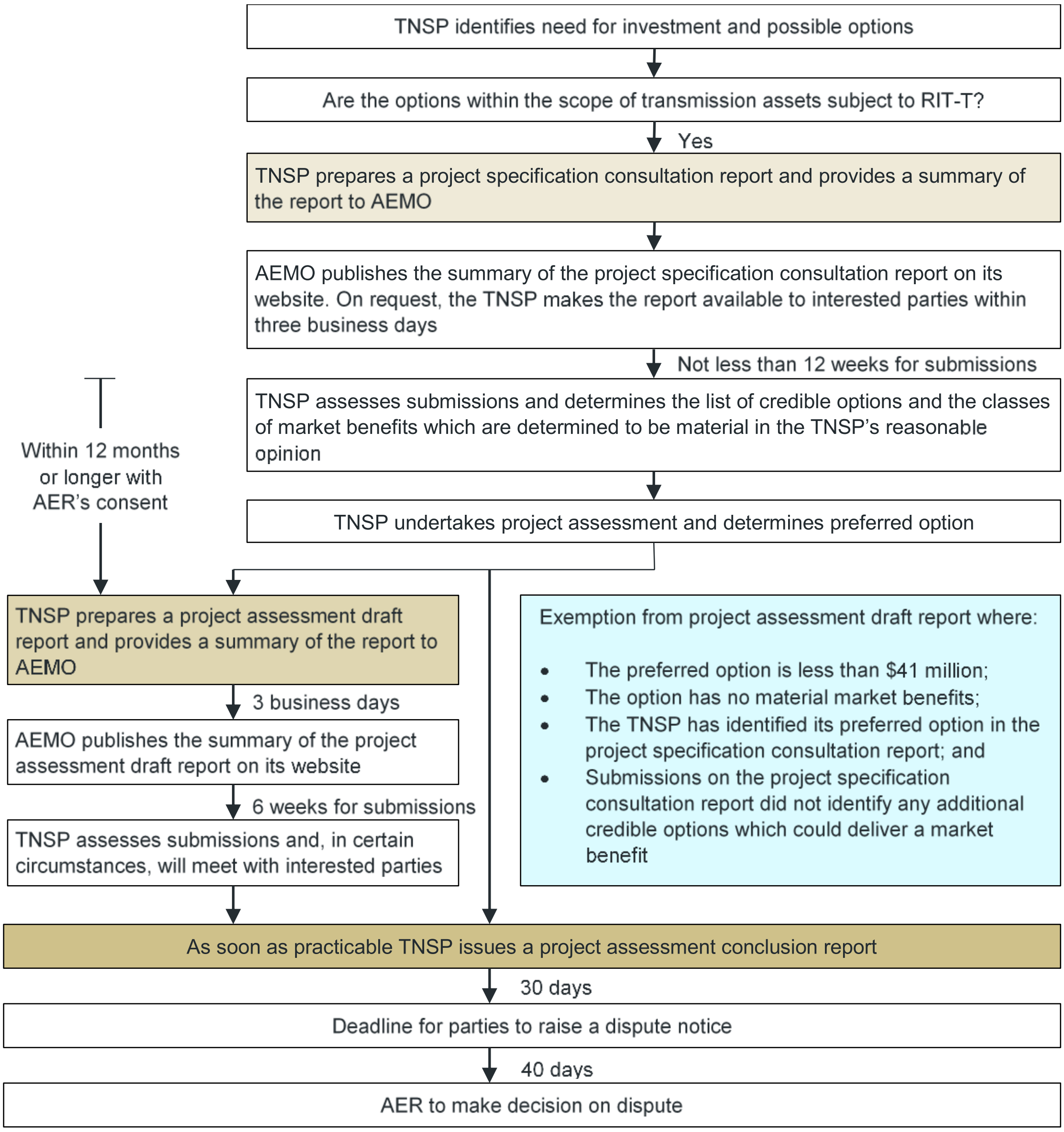
All laws, regulations, orders, licences, codes, determinations and other regulatory instruments (other than the Rules) which apply to Registered Participants from time to time, including those applicable in each participating jurisdiction as listed below, to the extent that they regulate or contain terms and conditions relating to access to a network, connection to a network, the provision of network services, network service price or augmentation of a network.

Applicable regulatory instruments	
AEMO	Australian Energy Market Operator
Base case	A situation in which no option is implemented by, or on behalf of the transmission network service provider.
Commercially feasible	An option is commercially feasible if a reasonable and objective operator, acting rationally in accordance with the requirements of the RIT-T, would be prepared to develop or provide the option in isolation of any substitute options. This is taken to be synonymous with 'economically feasible'.
Costs	Costs are the present value of the direct costs of a credible option.
Credible option	A credible option is an option (or group of options) that: 1. address the identified need; 2. is (or are) commercially and technically feasible; and 3. can be implemented in sufficient time to meet the identified need.
Economically feasible	An option is likely to be economically feasible where its estimated costs are comparable to other credible options which address the identified need. One important exception to this Rules guidance applies where it is expected that a credible option or options are likely to deliver materially higher market benefits. In these circumstances the option may be "economically feasible" despite the higher expected cost. This is taken to be synonymous with 'commercially feasible'.
Identified need	The reason why the Transmission Network Service Provider proposes that a particular investment be undertaken in respect of its transmission network.
Market benefit	Market benefit must be: a) the present value of the benefits of a credible option calculated by: i. comparing, for each relevant reasonable scenario: A. the state of the world with the credible option in place to B. the state of the world in the base case, And ii. weighting the benefits derived in sub-paragraph (i) by the probability of each relevant reasonable scenario occurring. b) a benefit to those who consume, produce and transport electricity in the market, that is, the change in producer plus consumer surplus.
Net market benefit	Net market benefit equals the market benefit less costs.
Preferred option	The preferred option is the credible option that maximises the net economic benefit to all those who produce, consume and transport electricity in the market compared to all other credible options. Where the identified need is for reliability corrective action, a preferred option may have a negative net economic benefit (that is, a net economic cost).
Reasonable Scenario	Reasonable scenario means a set of variables or parameters that are not expected to change across each of the credible options or the base case.

Appendix C Process for implementing the RIT-T

For the purposes of applying the RIT-T, the NER establishes a typically three stage process, ie: (1) the PSCR; (2) the PADR; and (3) the PACR. This process is summarised in the figure below (in gold), as well as the criteria for PADR exemption that this RIT-T is seeking to apply (in blue).

Figure 8 The RIT-T assessment and consultation process



Source: AER, Final Regulatory investment test for transmission application guidelines, 18 September 2017, p. 42.

ElectraNet