ElectraNet

MANAGING THE RISK OF INSTRUMENT TRANSFORMER FAILURE

Project Specification Consultation Report

8 October 2019

Executive Summary

We propose to replace 179 instrument transformers as part of our continued safe and efficient maintenance of the South Australian transmission network

This Project Specification Consultation Report (PSCR) identifies the need to replace 179 instrument transformers across the South Australian electricity transmission network as the most efficient solution to manage the failure risk of these assets based on their assessed condition and inherent risks.

Instrument transformers are a major component of the electrical protection system that ensures electrical faults are cleared within designated times, as specified in the National Electricity Rules (NER).[1] If an instrument transformer fails explosively, it can cause unpredictable damage resulting in harm to people, potential substation failure and consequent involuntary load curtailment for customers.

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

Instrument transformers are critical to the operation of protection systems, which in turn are critical to the safe, reliable and secure operation of the transmission system.

The identified need for this project is to continue to provide safe and reliable electricity transmission services in South Australia at a prudent and efficient level of cost. Specifically, the identified need for this Regulatory Investment Test for Transmission (RIT-T) is to efficiently manage the risk of failure of individual instrument transformers that are reaching, or have passed, the end of their technical lives based on their condition.

We have classified this RIT-T as a 'market benefits' driven RIT-T as the economic assessment is not being progressed specifically to meet a mandated reliability standard, but by the expected net benefits to customers.

However, the replacement program will also ensure compliance with a range of obligations under the NER and jurisdictional instruments (which is not expected to be the case under the base case). Specifically, Option 1 maintains compliance with:

- system standards and specifically the relevant fault clearance times;
- network reliability (S5.1.2):
  - when planning and operating the network we must consider a credible contingency event where the disconnection of any single generating unit or transmission line occurs and assume that the fault will be cleared in primary protection time;
  - ensuring that for all lines above 66kV the line's protection system is always available, other than for a short period (not greater than eight hours) whilst maintenance is carried out;
- protection systems and the fault clearance times applicable (including the fault clearance times mentioned in maintaining system security).

[1] S5.1a.8 of the NER outlines the requirements regarding fault clearance times, including the specific maximum permitted fault clearance times.

In addition, the *South Australian Electricity (General) Regulations 2012* (the Regulations), under the *Electricity Act 1996*, require that "*a system of maintenance must be instituted for protection and earthing systems and their components including…managed replacement programs for components approaching the end of their serviceable life*". [2]

ElectraNet considers this RIT-T forms an important part of complying with this requirement and, more broadly, avoids a situation of run-to-failure for the identified assets (which would not constitute a compliant management strategy).

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 credible option

The analysis has identified that there is only one technically feasible option, which is to replace the end-of-life instrument transformers. This is because the assets play a specific and important role in enabling substations to operate and to be maintained in a timely fashion, by minimising any consequential effects of asset failures on downstream customers through potential uncleared faults or explosive asset failures.

The estimated capital cost of this option is approximately $12 million, which equates to approximately $66,600 for each of the new instrument transformers planned to be installed.

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 driven by the unique and specific role that the identified instrument transformers play in the transmission of electricity and their relatively low replacement cost.

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

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

We have developed three reasonable scenarios for the economic assessment as shown in Table 1 below.

[2] *South Australia Electricity (General) Regulations 2012*, Schedule 3—Requirements for substations, clause 11(2).

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[3]	8.95 per cent	5.90 per cent	2.85 per cent
Avoided emergency corrective maintenance and opex	70 per cent of base estimates	Base estimates	130 per cent of base estimates
Avoided substation damage due to explosive failure	70 per cent of base estimates	Base estimates	130 per cent of base estimates
Reduced personal injuries from an explosive failure	70 per cent of base estimates	Base estimates	130 per cent of base estimates
Cost of involuntary load shedding	70 per cent of base estimates	Base estimates	130 per cent of base estimates

These describe:

- a 'central' scenario – reflecting our base set of key assumptions;
- a 'low benefits' scenario – reflecting a pessimistic set of assumptions, which represents a lower bound on potential market benefits that could be realised; and
- a 'high benefits' scenario – reflecting an optimistic set of assumptions, which represents an upper bound on potential market benefits that could be realised.

Replacing the identified instrument transformers as soon as possible is the preferred option[4]

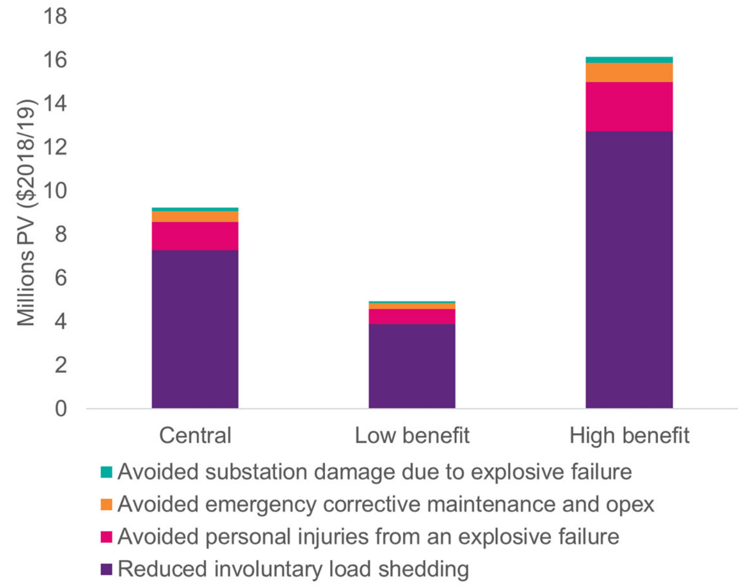
The preferred option that has been identified in this assessment for addressing the identified need is Option 1, i.e. replacing the 179 instrument transformers between 2020 and 2023.

The majority of the expected benefits are derived from the avoided risk of instrument transformer failure and the reduced time taken to resolve such failures. These are primarily comprised of avoided expected unserved energy.

3 Expressed on a real, pre-tax basis

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

Figure 1 - Breakdown of present value gross economic benefits of Option 1



On a weighted-basis (i.e., weighted across the three scenarios investigated), Option 1 is expected to deliver approximately $2.6 million in net market benefits.

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 tested the optimal timing and the sensitivity of this timing to key variables. These sensitivity tests find that commissioning Option 1 as soon as possible is optimal and there are expected to be strong estimated net market benefits.

Contents

Figures

TABLES

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
PV	Present value
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 Project Specification Consultation Report (PSCR) represents the first step in the application of the RIT-T to address the risk of instrument transformer failure at certain substations in the South Australian transmission network.

This report:

- describes the identified need that 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 option that we consider addresses 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 option 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.[5]

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

The credible option discussed in this PSCR has not been foreshadowed in AEMO's National Transmission Network Development Plan (NTNDP) or Integrated System Plan as these assets 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 6 January 2019. 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.

5 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 instrument transformers was well-advanced by 30 January 2018, the project was not yet 'committed'. Accordingly, we have subsequently initiated this RIT-T to consult on its proposed expenditure related to replace the identified instrument transformers.

Subject to submissions received on this PSCR, a Project Assessment Conclusions Report (PACR) is expected to be published by 18 March 2020.

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

Rainer Korte
Group Executive Asset Management
ElectraNet Pty Ltd
consultation@electranet.com.au

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 instrument transformers and their role in the wider transmission of electricity in South Australia.

2.1 Background to the identified need

'Instrument transformers' is a general term used to refer to current and voltage devices that change currents and voltages from one magnitude to another or perform an isolating function, i.e., isolate the utilisation current or voltage from the supply voltage for safety to both the operator and the end device in use. Instrument transformers are designed specifically for use with electrical equipment falling into the broad category of devices commonly called instruments such as voltmeters, ammeters, wattmeters, and watt-hour meters, etc.[6]

Instrument transformers are a major component of the electrical protection system that ensures faults are cleared within designated times, as stipulated by the National Electricity Rules (NER).[7] In addition, if an instrument transformer fails explosively it can cause unpredictable damage resulting in potential substation failure and consequential involuntary load curtailment for consumers.

Four instrument transformers at the Torrens Island B substation are illustrated Figure 2.

Figure 2 - Endurance 275 kV post current transformers at Torrens Island B circa 1974

[6] GE, *Instrument Transformer Basic Technical Information and Application*, p. 3 – available at: https://www.gegridsolutions.com/products/manuals/ITITechInfo.pdf

[7] S5.1a.8 of the NER outlines the requirements regarding fault clearance times, including the specific maximum permitted fault clearance times.

Instrument transformers are essential to the task of transmitting electricity, without them the transmission network could not perform safely and efficiently.

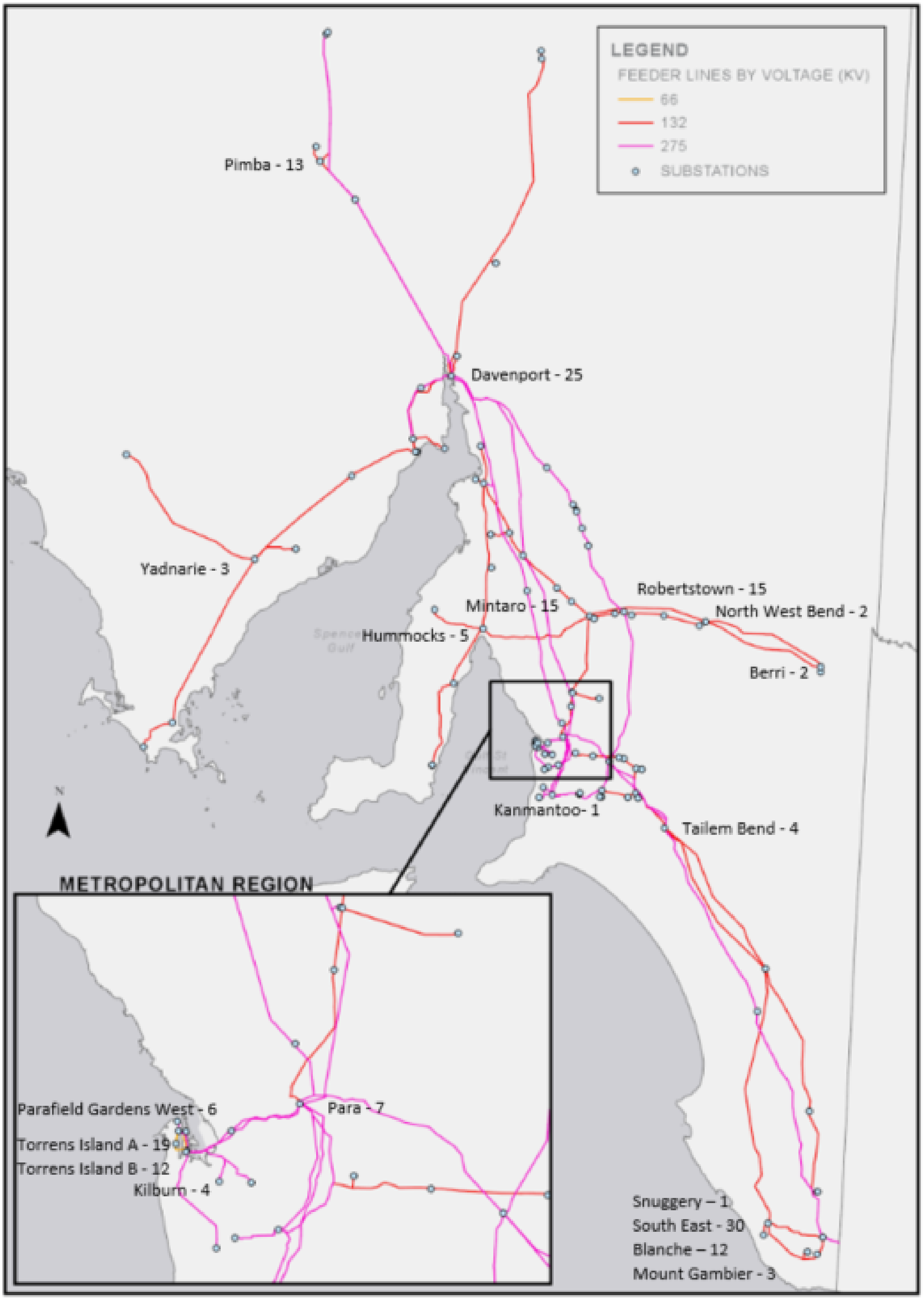
Across our transmission network, we have identified 179 instrument transformers for replacement based on their age and condition. In particular, we have identified:

- 124 Current Transformers;
- 46 Capacitor Voltage Transformers; and
- 9 Voltage Transformers.

Of the 124 Current Transformers that have been identified for replacement, 3 Current Transformers at the Para substation are planned to be replaced with post insulator supports for the west bus.

The distribution of the 19 substations where instrument transformers are planned to be replaced is illustrated in Figure 3. Specifically, it shows the number of existing transformers identified for replacement at each substation.

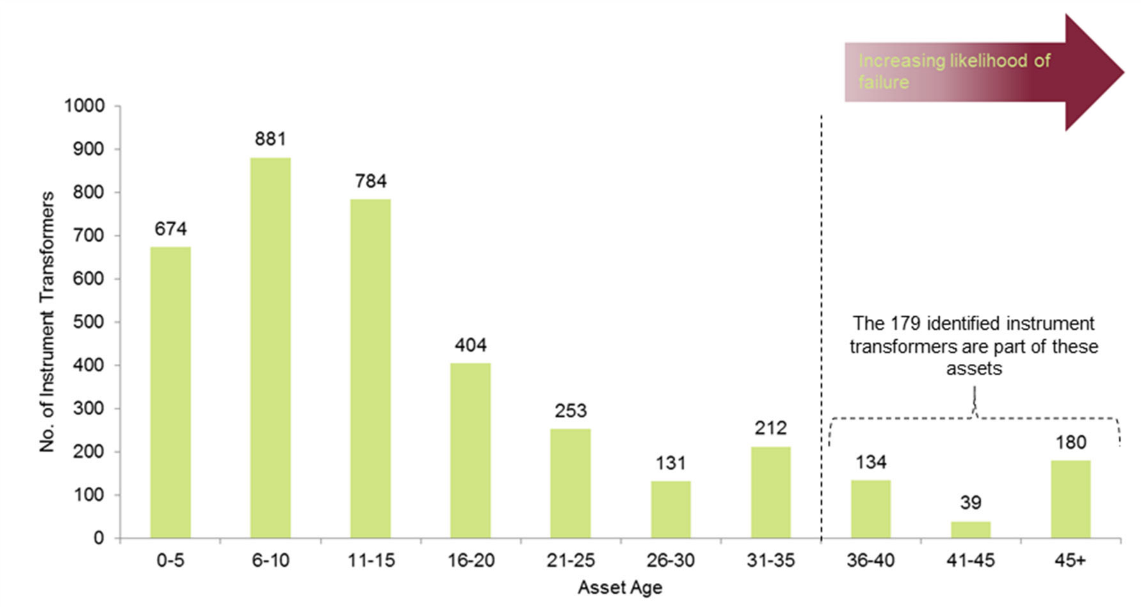
Figure 3 - Location of the instrument transformers that are being replaced



The instrument transformers to be replaced have a standard life[8] of 44.8 years and are now mostly aged between 36 and 58 years. These instrument transformers are planned to be replaced one for one with new instrument transformers with the same technical capacity.

If the replacement program is not implemented, it is expected that a number of these assets will fail explosively at an increasing rate going forward, causing unpredictable damage resulting in potential substation failure and involuntary load shedding on parts of the network. Also, if the replacement program is not implemented there will be an increased cost to replace the assets upon failure in a reactive fashion.

Figure 4 - Age profile of instrument transformers and increasing level of failure



This replacement program will also create cost savings by avoiding substation damage, outages and personal injuries that could result from an explosive failure. The existing porcelain instrument transformers have much higher likely consequences when an explosive failure occurs, compared to the polymer instrument transformers that are replacing the porcelain instrument transformers.

When a porcelain instrument transformer explodes, there is the possibility of considerable damage caused to other substation assets, resulting in a high likelihood of an outage and, if the substation is attended at the time, significant fatality risks. The avoidance of explosive failure and decreased likelihood of adverse consequences from an explosive failure will create cost savings across these two areas during the delivery of the program (compared to a 'replace on failure' strategy, which is assumed under the base case in this RIT-T assessment).

[8] 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 instrument transformers for context and note that the assessment of replacing the identified transformers, both in the Revenue Proposal and this RIT-T, is consistent with the concept of economic life; ie, the expenditure decision is primarily based on the existing asset's inability to efficiently maintain its service performance requirement.

In March 2017, there was an explosive failure of a capacitor voltage transformer at the Torrens Island switchyard that placed the South Australian electricity network at significant risk. Specifically, while there was a localised outage, the only reason there was not a significant loss of load at the time was due to the voltage levels at South East substation being within the lower limits, so the Heywood Interconnector could continue to be connected.

The explosive failure of a porcelain capacitor voltage transformer at the Torrens Island switchyard caused significant damage, disconnecting three generation units at Torrens Island Power Station and resulted in Pelican Point Power Station also tripping off due to the operation of its over current protection (that was external to the power station).

The restoration of the connection points and substation took months to complete with a temporary bypass available for the less damaged connection points within two to three days.

For more information on the fault at the Torrens Island switchyard, and its effects, please refer to the AEMO incident report that was published at the time.[9]

2.2 Description of the identified need for this RIT-T

Instrument transformers are required in the operation of protection systems, which in turn are critical to the safe, reliable and secure operation of the transmission system.

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

We have assessed the condition, and timing for the ultimate replacement of instrument transformer units as part of our ongoing asset management processes. There is an increased likelihood that a number of these assets will fail in coming years given their current age, potentially resulting in the unplanned unavailability to parts of the network, personal injury to substation workers and greater operating costs to ElectraNet.

We have classified this RIT-T as a 'market benefits' driven RIT-T as the economic assessment is not being progressed specifically to meet a mandated reliability standard but by the expected net benefits to customers.

However, the replacement program will also ensure compliance with a range of obligations under the NER and jurisdictional instruments (which is not expected to be the case under the base case). Specifically, Option 1 maintains compliance with:

- system standards and specifically the relevant fault clearance times;
- network reliability (S5.1.2):
    - when planning and operating the network we must consider a credible contingency event where the disconnection of any single generating unit or

[9] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Report-SA-on-3-March-2017.pdf

transmission line occurs and assume that the fault will be cleared in primary protection time;

- ensuring that for all lines above 66kV the line's protection system is always available, other than for short period (not greater than eight hours) whilst maintenance is carried out;

- protection systems and the fault clearance times applicable (including the fault clearance times mentioned in maintaining system security).

In addition, the *South Australian Electricity (General) Regulations 2012* (the Regulations), under the *Electricity Act 1996*, require that "*a system of maintenance must be instituted for protection and earthing systems and their components including…managed replacement programs for components approaching the end of their serviceable life*". [10] ElectraNet consider this RIT-T forms an important part of complying with this requirement and, more broadly, avoids a situation of run-to-failure for the identified assets (which would not constitute a compliant management strategy).

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 details on the risk cost modelling framework.

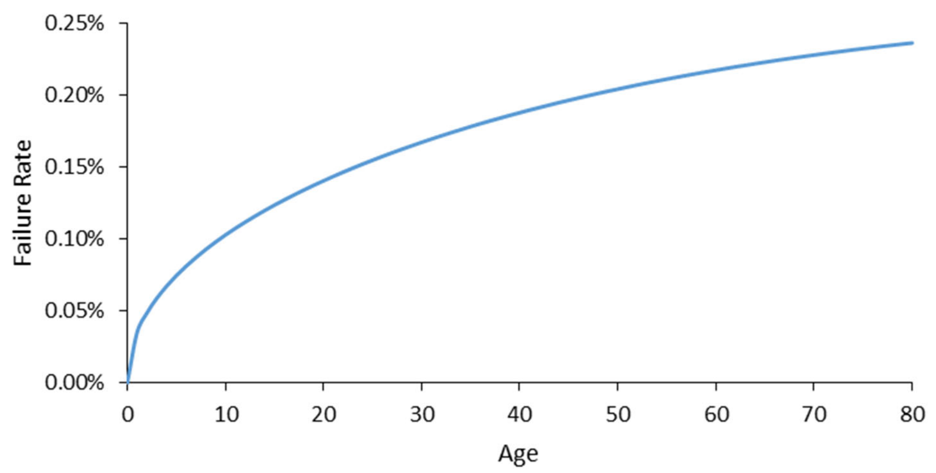
2.3.1 The probability of instrument transformers failing

The probability of failure (PoF) is estimated by considering the asset's age and historical asset failure data from CIGRE's *Final Report 2004 – 2007 International Enquiry on Reliability of High Voltage Equipment, Part 4 – Instrument Transformers*. CIGRE is a global technical forum for large electric systems and is composed of researchers, academics, engineers, technicians, suppliers, market and system operators and other decision makers.

Figure 5 below summarises the modelled PoF for the identified instrument transformers, which shows an increase in the PoF as the assets increase in age.

[10] *Electricity (General) Regulations 2012 (SA)*, Schedule 3—Requirements for substations, clause 11(2).

Figure 5 - Weibull distribution of instrument transformer failure over age



2.3.2 The adverse effects of instrument transformer failure

The risk cost model considers six potential failure modes for instrument transformers:

- electrical – when there is a loss of electrical connection integrity in primary and secondary components;
- electrical explosive – when the loss of electrical connection integrity in primary components results in an explosive failure;
- insulation – an internal and external dielectric failure, insulation leakage or accuracy out of tolerance;
- insulation explosive – an explosive internal and external dielectric failure or explosive insulation leakage failure;
- other – where the unit loses mechanical integrity; and
- other explosive – which is any other major failure where the unit loses mechanical integrity resulting in explosive failure.

Each of these failure modes have different characteristics and consequent likelihoods of occurring. The potential adverse consequences of an instrument transformer failure include:

- prolonged periods of unserved energy to electricity customers during the time taken to establish a temporary connection in response to an explosive failure;
- increased operating expenditure required to manage the network during an outage event;
- additional corrective maintenance costs associated with having to repair or replace the instrument transformer in an unplanned emergency;
- increased substation damage due to an explosive instrument transformer failure; and
- significant risk of fatalities if workers are present at the substation during an explosive instrument transformer failure.

2.3.3 The likelihood and cost of consequences of an instrument transformer failure

Our risk cost model, models each of the adverse effects outlined above that could occur from an instrument transformer failure. Specifically, the risk cost model individually defines a set of assumptions for the adverse effects, which allows the 'likelihood of consequence' (LoC) and 'cost of consequence' (CoC) to be estimated for instrument transformer failures.

While the largest expected source of benefit from the planned replacement comes from avoided outages following a failure of an instrument transformer, most non-explosive failures of instrument transformers will not result in an outage, due to the presence of duplicated systems. The only non-explosive failures that will result in an outage are on single radial instrument transformers, therefore the benefits from outages relating to non-explosive failures are limited.

When there is an explosive failure of a porcelain instrument transformer, the likelihood that there will be an outage is assumed to be between 1 and a 100 per cent. This likelihood depends on several considerations including whether the substation is part of the meshed network and the distance between the location of the instrument transformer to other assets critical to supplying energy.

If the instrument transformer is instead a polymer instrument transformer the likelihood that there will be an outage is reduced to between 0.01 – 1.00 per cent. We have assumed that any outage is likely to be for 48 hours, based on the typical time to resupply the damaged substation or connection point via an alternative temporary connection. This temporary connection point would likely be in place for approximately 3 months whilst repairs are undertaken to the substation.

It is also assumed in specific instances that if there is an explosive failure of certain instrument transformers that support the interconnector there is a possibility of a wide scale outage. However, the LoC for this to occur is only when the interconnector is importing above the relevant limits (i.e. very unlikely).

In calculating outage costs, AEMO's estimated value of customer reliability (VCR) of a mixed load for South Australia, escalated to 2019 dollars, has been applied for all connection points when the connection point is not directly connected to a customer. When the connection point is directly connected to a customer the value of customer reliability of a direct connect load has been applied. All loads are based on the average load from the financial year 2017-18.

We note that, should an instrument transformer fail, there may also be wider outages than the load groups we have considered and/or planned outages for operational and capital work may have to be postponed.

These additional adverse effects have not been captured in our risk cost modelling since, doing so, would require a significant modelling exercise and it is not considered material in the context of the RIT-T assessment (i.e. in identifying the preferred option) but are expected to further increase the net market benefits associated with Option 1.

Unplanned outages require ElectraNet to incur further operating expenditure relating to the management of our network, including media, legal and investigation costs. These costs have been estimated using historical information and experience by the relevant internal teams at ElectraNet.

The explosive failure of an instrument transformer may in some cases cause material damage to other assets within the substation that will then require replacement or significant corrective work, resulting in additional costs. These costs have been estimated using historical information and experience by the relevant internal teams at ElectraNet.

We note that there is a material risk of fatality if someone is at a substation when a porcelain instrument transformer explodes. The substations where the instrument transformers are proposed to be replaced have been classified based on their size with larger substations more likely to be attended by industry workers on a regular basis.

We have used the Value of Statistical Life[11], escalated to today's dollars and multiplied by a relevant disproportionate factor, in order to quantify these avoided consequences. It has also been assumed that any such events will incur additional costs such as a legal, compensation and investigation costs (which have been estimated using Safe Work Australia reports).[12] It is noted if the instrument transformer is a polymer instrument transformer the risk of fatality from an explosive failure is significantly reduced.

Overall, the costs associated with the negative consequences of an instrument transformer failure are material assumptions for the economic assessment of the project. We have therefore included a range of sensitivity tests on these as part of the economic assessment.

[11] Department of the Prime Minister and Cabinet, *Best Practice Regulation Guidance Note Value of statistical life*, October 2018.

[12] Average Indirect Costs for work-related incidents, Australia in June 2013$, The Cost of Work-related Injury and Illness for Australian Employers, Workers and the Community: 2012-13, Safe Work Australia, p.26

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 instrument transformers. This is because the assets play a specific and important role in enabling substations to operate and to be maintained in a timely fashion, by minimising any consequential effects on downstream customers through potential uncleared faults or explosive asset failures.

We have however investigated different assumed timings for this work in order to determine the optimal timing. This assessment is presented in section 7.4.

The option is considered to be technically and economically feasible and able to be implemented in sufficient time to meet the identified need.[13]

3.1 Option 1 – Planned replacement of instrument transformers by 2024

Option 1 involves a planned replacement of 55 Voltage Transformers and 124 Current Transformers that are aged between 36 and 58 years and have been assessed to be at end of life based on their age and/or condition. The existing porcelain instrument transformers will be replaced with polymer instrument transformers.

These replacements are planned to occur over several priority-ranked streams between 2020 and 2023. These replacements are to be performed at substation locations where no other capital projects are scheduled to undertake replacement of the identified instrument transformers from the 2018-2023 regulatory period.

All instrument transformer replacement assets are assumed to have the same signal output levels, ratios, etc. as the original assets, negating the requirement to modify any secondary system inputs. It is envisaged that minimal changes will be required with a like for like change of the instrument transformers.

The estimated total capital cost of this option is approximately $11.9 million. This equates to approximately $66,600 for each of the 179 total new transformers planned to be installed.

There is no incremental change in routine maintenance when the assets are replaced under Option 1 compared to the base case.

It is estimated that the replacement time for an instrument transformer at site is around one week; i.e. around 3 years in total. We estimate that all instrument transformers could be replaced and commissioned by 2023 under this option.

3.2 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 instrument transformers does not lend itself to any solution other than to replace the assets as the only technically and economically feasible option given the unique and specific function of these assets.

13 In accordance with those identified in section 2.2.

One conceivable option, for example, would be to replace the entire substation, as opposed to just the instrument transformers. However, the capital cost of this is expected to be in the order of $20-40 million per substation, which is significantly more than the option outlined above and does not provide any additional market benefits. In addition, the condition of other substation assets is such that they do not require replacing in coming years. Therefore, this is not considered to be an economically feasible option.

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

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

We have considered whether the credible option is expected to have a material inter-regional impact.[14]

By reference to AEMO's screening test for an inter-network impact[15], a material inter-regional impact may arise if the option:

- involves a series capacitor or modification near an existing series capacitor;
- is expected to result in a change in power transfer capability between South Australia and neighbouring transmission networks; or
- is expected to increase fault levels at any substation in another TNSP's network.

As none of these criteria are satisfied for this RIT-T, ElectraNet does not consider there are any associated material inter-network impacts.

---

[14] In accordance with NER clause 5.16.4(b)(6)(ii).

[15] 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.

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 instrument transformers play in the transmission of electricity as specialised pieces of equipment and their relatively low replacement cost (approximately $66,600 per instrument transformer).

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

Instrument transformers are required for the operation and maintenance of substations as outlined in section 2. Substation assets and, consequently, a substation would not be able to function in a safe manner without instrument transformers.

A network support option that avoids replacement of instrument transformers would therefore need to be able to replicate the functionality, capacity and reliability of the entire substation on an enduring basis at a cost that is lower than the network option currently under consideration.

At this point in time, we estimate that it is possible the following substations are likely to need emergency replacement, incur unserved energy and/or require generation support following possible damage caused by the explosive failure of an instrument transformer.

Table 2 - Substations at risk of unserved energy and/or requiring generation support under base case

Berri	Blanche	Davenport	Hummocks
Kanmantoo	Kilburn	Mintaro Switching Station	Mount Gambier
North West Bend	Para	Parafield Gardens West	Pimba Switching Station
Robertstown	South East	Snuggery	Tailem Bend
Torrens Island A	Torrens Island B Switching Substation	Yadnarie	

The average load at these substations is approximately 30 MW. A network support option would be required to be able to meet or offset these loads in full on a continuous basis, possibly 24 hours a day, during the time taken to or restore a substation impacted by an explosive failure of an instrument transformer. While network support options involving generation may be technically possible, such a solution at the scale required is unlikely to be economically feasible.

Any network support solution seeking to remove the need for any of the affected instrument transformers would also 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.[16]

Many of the expected benefits associated with Option 1 are captured in the expected costs avoided by the option (i.e., the avoided expected costs compared to the base case). As described in section 2, these include avoided risk costs.

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

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 Option 1.

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 $37,000/MWh for mixed loads, which is an escalation of the value sourced from AEMO's 2014 Value of Customer Reliability Review,[17] for South Australia, and a VCR of $6,500 for direct connections.

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.[18]

Option 1 is not expected to impact on network constraints between competing generating centres and is therefore not expected to result in any change in dispatch outcomes and wholesale market prices. We note in section 2.1 that the March 2017 failure of an instrument transformer at Torrens Island did affect generators and there is a possibility of a wide scale outage from an explosive failure of some instrument transformers that support the interconnector.

However, any such market benefits relating to the wholesale market associated with Option 1 are not considered 'material' in the context of the RIT-T (since they do not affect the identified preferred option) and estimating any such market benefits would simply increase the estimated net market benefit of Option 1.

---

[16] 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.

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

[18] AER, *Final Regulatory Investment Test for Transmission Application Guidelines*, December 2018, p. 32.

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

- 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.

We consider that none of the three 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	Option 1 does not 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.[19] 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 age and 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 Option 1 maintains the same network capacity as current at the same location, there are not expected to be any differences in network losses.

[19] AER, *Final Regulatory Investment Test for Transmission Application Guidelines*, December 2018, p. 95.

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 replacing the identified transformers 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.

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 Option 1.

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.[20]

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.[21]

6.2 The discount rate and assessment period

The RIT-T analysis has been undertaken over a 20-year period from 2019 to 2038, which considers the size, complexity and expected life of each option to provide a reasonable indication of its cost.

The new instrument transformers have asset lives of 44.8 years. We have taken a terminal value approach to incorporating capital costs in the assessment, which ensures that the capital cost of the replacement program is appropriately captured in the 20-year assessment period.

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

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

We have adopted a real, pre-tax discount rate of 5.9 per cent as the central assumption for the NPV analysis presented in this report, consistent with Energy Network Australia's (ENA) 2019 RIT-T Economic Assessment Handbook.[22] 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.[23]

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 2.85 per cent,[24] and an upper bound discount rate of 8.95 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.

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.[25]

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; 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.

Given that the low and high benefits scenarios are less likely to occur, the scenarios have been weighted accordingly; 25 per cent – low benefits scenario, 50 per cent – central benefits scenario, and 25 per cent – high benefits scenario.

---

[22] ENA, *RIT-T Economic Assessment Handbook*, 15 March 2019, p. 67.

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

[24] This is equal to WACC (pre-tax, real) in the latest Final Decision for a transmission business in the NEM, see: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2019-24/final-decision

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

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[26]	8.95 per cent	5.90 per cent	2.85 per cent
Avoided emergency corrective maintenance and opex	70 per cent of base estimates	Base estimates	130 per cent of base estimates
Avoided substation damage due to explosive failure	70 per cent of base estimates	Base estimates	130 per cent of base estimates
Reduced personal injuries from an explosive failure	70 per cent of base estimates	Base estimates	130 per cent of base estimates
Cost of involuntary load shedding	70 per cent of base estimates	Base estimates	130 per cent of base estimates

[26] Expressed on a real, pre-tax basis

7. Assessment of the credible options

This section outlines the assessment we have undertaken of the credible network option. The assessment compares the option against a base case 'do nothing' option.

7.1 Gross benefits for each credible option

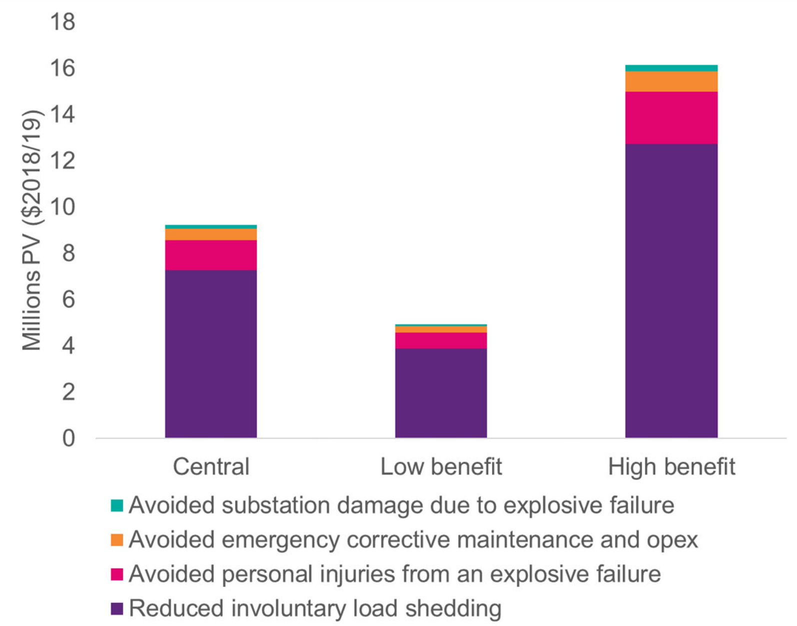
The gross benefits estimated for Option 1 relative to the 'do nothing' base case in present value terms are summarised in Table 5. The gross market benefit has been calculated for each of the three scenarios as outlined in section 6.3.

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

Option	Low benefits scenario	Central scenario	High benefits scenario
Option 1 – Planned replacement of instrument transformers by 2024	4.9	9.2	16.2

A breakdown of benefits is illustrated in Figure 6 and shows that the majority of benefits are derived from the reduction in involuntary load shedding. There are also benefits from the avoided personal injury risk associated with lower explosive failure consequences under Option 1, as well as avoided emergency corrective maintenance and opex.

Figure 6 - Breakdown of present value gross economic benefits of Option 1



As outlined in section 2.3.3, we note that, should an instrument transformer fail, there may also be wider outages than the load groups we have considered and/or planned outages for operational and capital work may have to be postponed. These additional adverse effects have not been captured in our risk cost modelling since, doing so, would require a significant modelling exercise and it is not considered material in the context of the RIT-T assessment but are expected to further increase the market benefits associated with Option 1.

7.2 Estimated costs for each credible option

The capital costs of Option 1, relative to the base case, in present value terms are summarised in Table 6.

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

Option	Low benefits scenario	Central scenario	High benefits scenario
Option 1 – Planned replacement of instrument transformers by 2023	-9.9	-7.3	-4.4

7.3 Net present value assessment outcomes

The net market benefit in NPV terms for Option 1 across the three scenarios, as well as on a weighted basis is summarised in Table 7. The net market benefit is the gross benefits (as set out in section 7.1) minus the cost (as outlined in section 7.2), all expressed in present value terms.

The table below demonstrates that Option 1 provides an expected net economic benefit on a probability-weighted basis, as well as under the central and high scenarios.

While the low benefits scenario shows negative expected market benefits, this scenario is relatively unlikely because it is comprised of the lower bound of each expected net market benefit resulting in a more extreme scenario. As outlined in Table 7, the low scenario is based on including 30 per cent higher capital costs, a commercial discount rate of 8.95 per cent and 70 per cent lower benefits (across all types of benefits).

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

Option	Low benefits scenario	Central scenario	High benefits scenario	Weighted
Option 1 – Planned replacement of instrument transformers by 2023	-4.9	1.9	11.7	2.6

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 tested the optimal timing of the project, and the sensitivity of this timing to key variables.

We have then tested the sensitivity of the total net market benefit to variations in the key factors underlying the assessment, such as for example the sensitivity of the project to increases in capital costs (all sensitivities tested are examined in section 7.4.2).

7.4.1 Sensitivity testing of the assumed optimal timing for the credible option

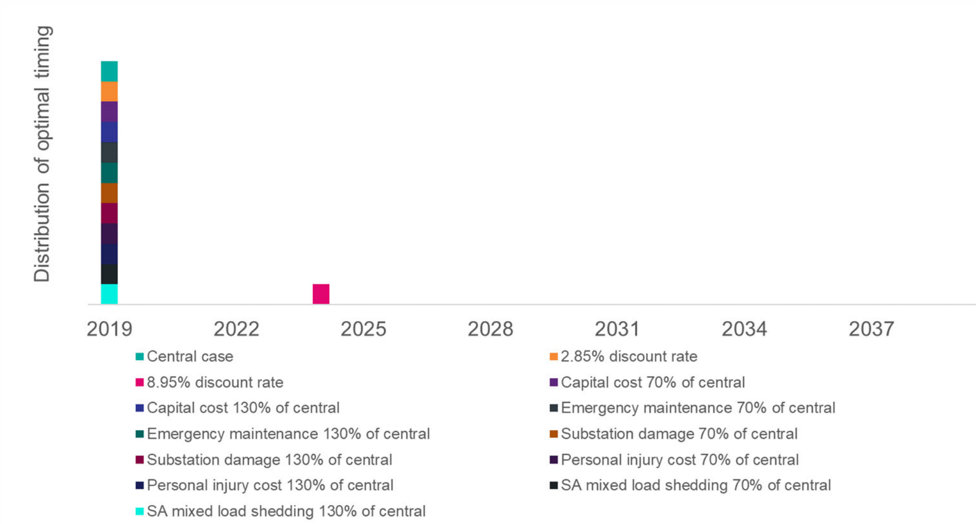
We have estimated the optimal timing for Option 1 based on the year when the present value of the benefits exceeds the present value of the replacement project costs,[27] which is consistent with when the expected NPV is maximised. This process was undertaken for both the central set of assumptions and also a range of alternative assumptions for key variables.

The impact on the optimal year to commence the program is outlined in Figure 7 under a range of alternative assumptions. Specifically, it shows, for each set of sensitivities/assumptions, the year that results in the highest expected net market benefits, all else being equal.

The figure illustrates that the optimal commissioning date is as soon as possible for all except one of the sensitivities investigated. Specifically, under a high assumed commercial discount rate (of 8.95 per cent), the optimal timing is delayed until 2023. However, on balance, we consider the investment is required as soon as possible.

It is noted that the figure below shows the optimal year to *commence* the program of replacement, whilst recognising that it will take three years to complete the replacement works (i.e., the earliest all transformers can be replaced is mid-2023).

Figure 7 - Distribution of optimal timing for Option 1 under a range of different key assumptions



7.4.2 Sensitivity of the overall net market benefit

We have also looked at the consequences for the credible option of 'getting it wrong' if the key underlying assumptions are not accurate.

The four figures below illustrate the estimated net market benefits for each option if the four separate key assumptions in the central scenario are varied individually. Importantly, for the majority of the sensitivity tests shown below, the estimated net market benefit of Option 1 is found to be strongly positive.

27 We note that this approach is consistent with the recently updated AER RIT-T Guidelines (see: AER, *Regulatory Investment Test for Transmission*, Application Guidelines, December 2018, p. 21).

The table below demonstrates the 'threshold' values for each of the key assumptions, i.e., how much would each key assumption need to be changed by for Option 1 to no longer have positive net market benefits.

Table 8 - Threshold values for key assumptions for Option 1 to no longer have positive net market benefits

Key variable/parameter	Threshold value
Capital cost	126% of central estimate
Discount rate[28]	8.13%
Value of customer reliability	74% of central estimate
Emergency corrective maintenance, substation damage costs and personal injury costs	No value[29]

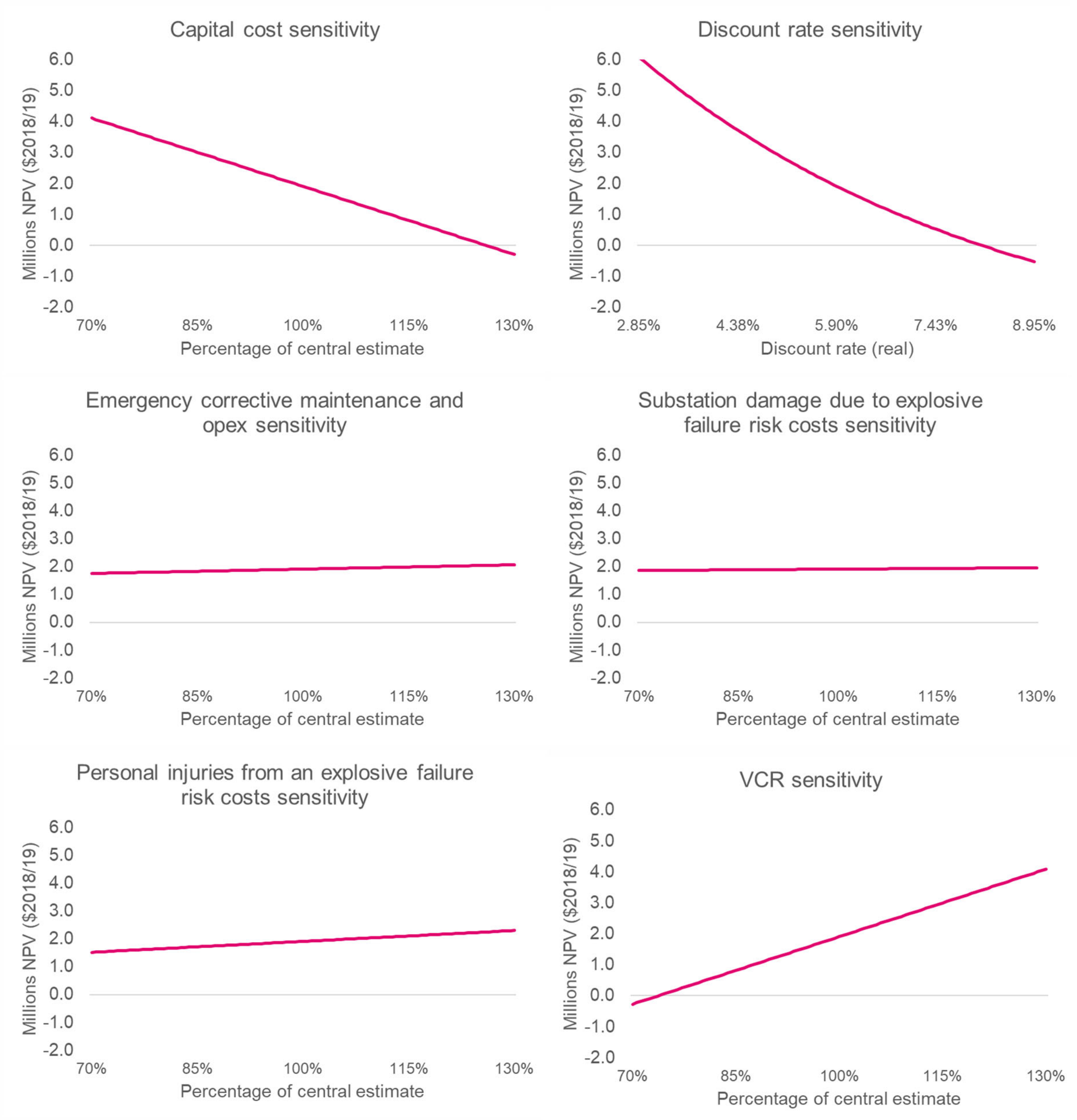
In addition, we find that the modelled failure rate implicit in the risk cost modelling would need to fall to approximately 79 per cent of the central estimate in order for there to be zero estimated net market benefits under the central scenario.

ElectraNet does not consider that any of these threshold values can be reasonably expected and, thus, considers that the expected net market benefits have been demonstrated to be robust to a range of alternate assumptions.

[28] Expressed on a real, pre-tax basis

[29] I.e., if each of these categories was removed completely (individually), Option 1 would still have a positive expected net market benefit.

Figure 8 - Sensitivity testing of the NPV of net market benefits



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 instrument transformers between 2020 and 2023. This option is described in section 3 and is estimated to have a capital cost of $11.9 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. In addition, Option 1's replacement program ensures ongoing compliance with a range of obligations under the NER and jurisdictional instruments.

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 $43 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.

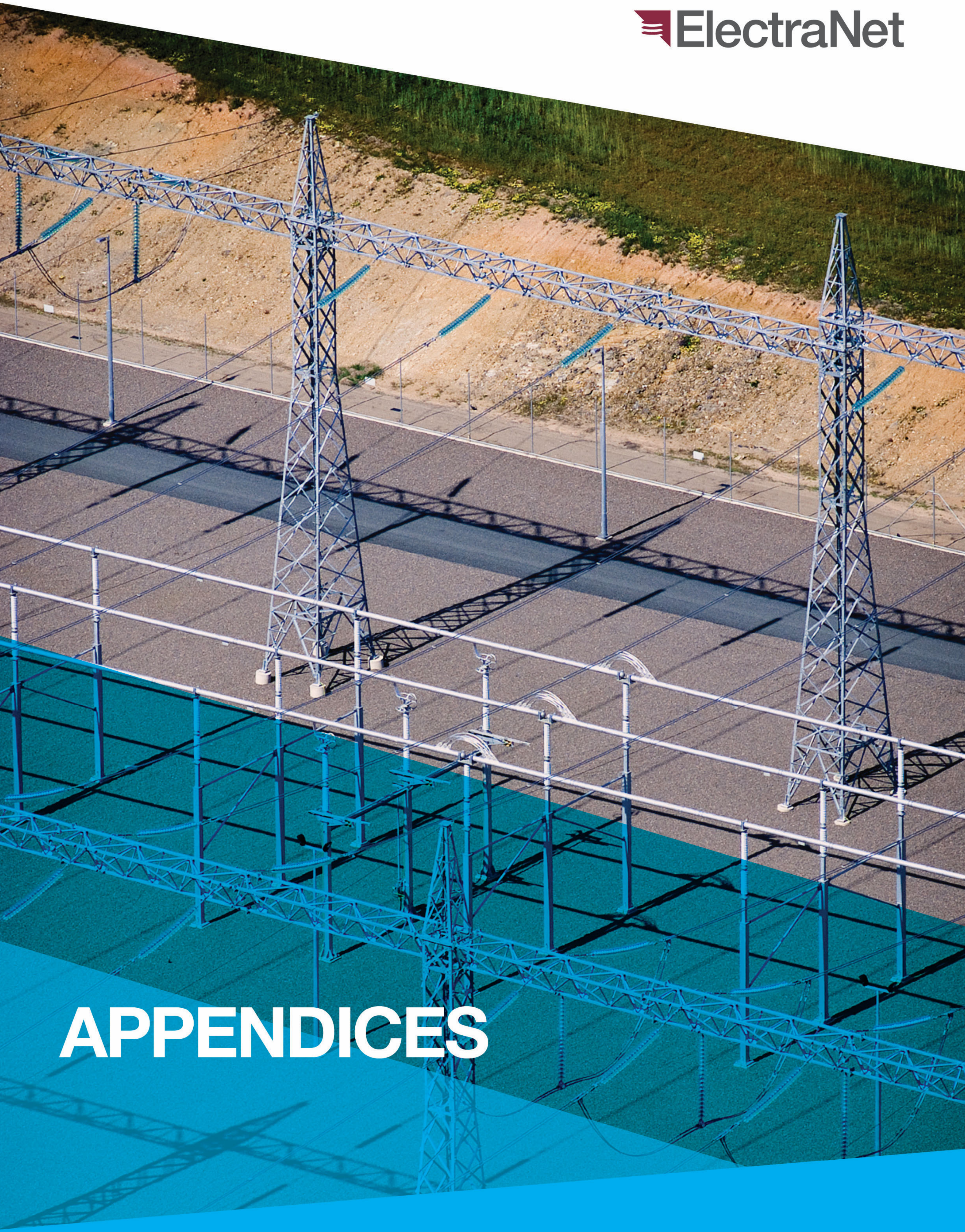
We consider that its investment in relation to Option 1 is exempt from producing a PADR under NER clause 5.16.4(z1) on the basis of meeting the criteria above.

In accordance with NER clause 5.16.4(z1)(4), the exemption from producing a PADR is dependant on any submissions received in response to this PSCR. 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 for this PSCR, 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.[30]

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

ElectraNet



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 NER version 124.

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	3 & 5

Rules clause	Summary of requirements	Relevant section(s) in PSCR
	(v) to the extent practicable, the total indicative capital and operating and maintenance costs.	
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

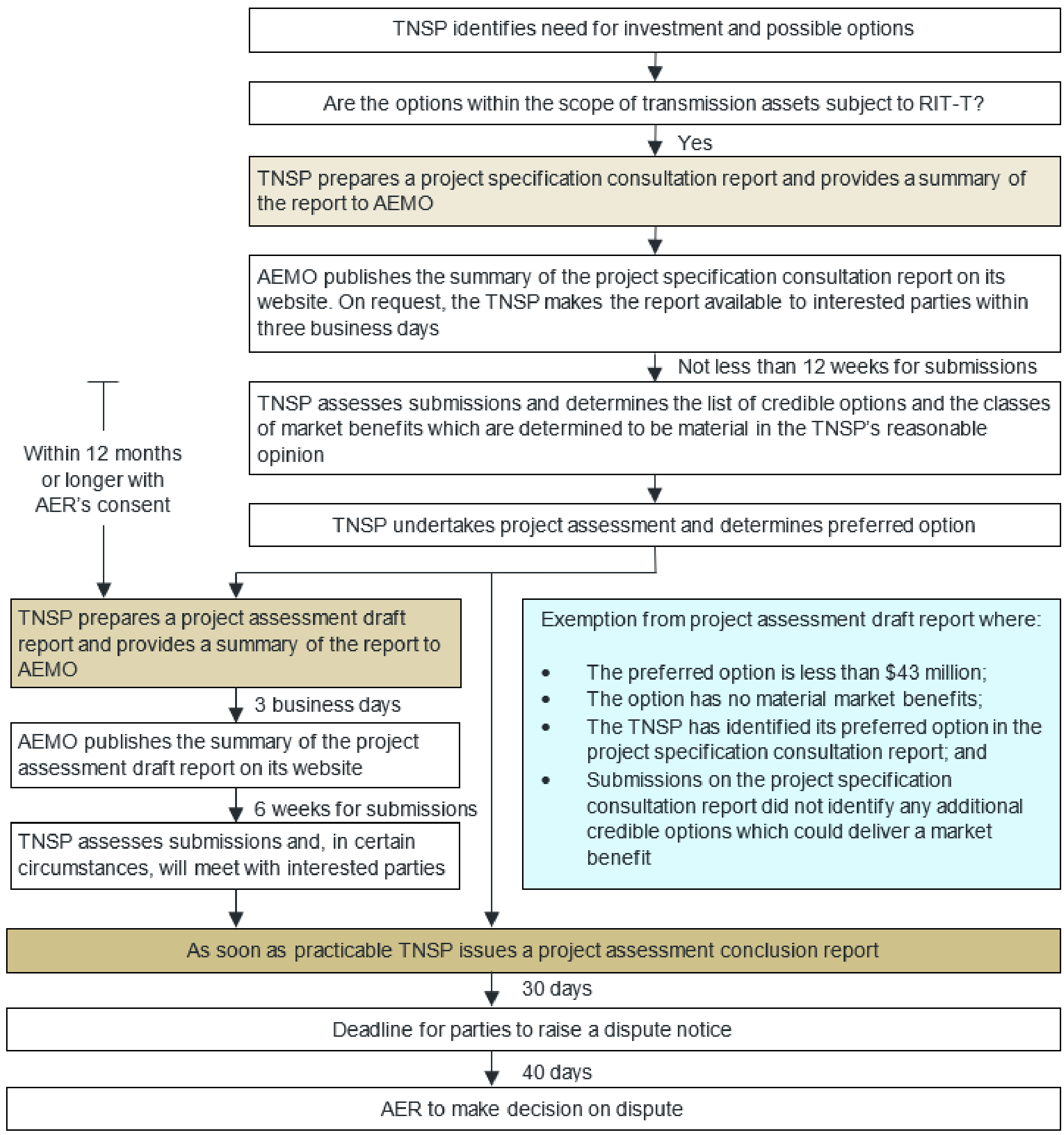
All laws, regulations, orders, licences, codes, determinations and other regulatory instruments (other than the NER) which apply to Registered Participants from time to time, including those applicable in each participating jurisdiction as listed below, to the extent that they regulate or contain terms 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 9 - The RIT-T assessment and consultation process



ElectraNet