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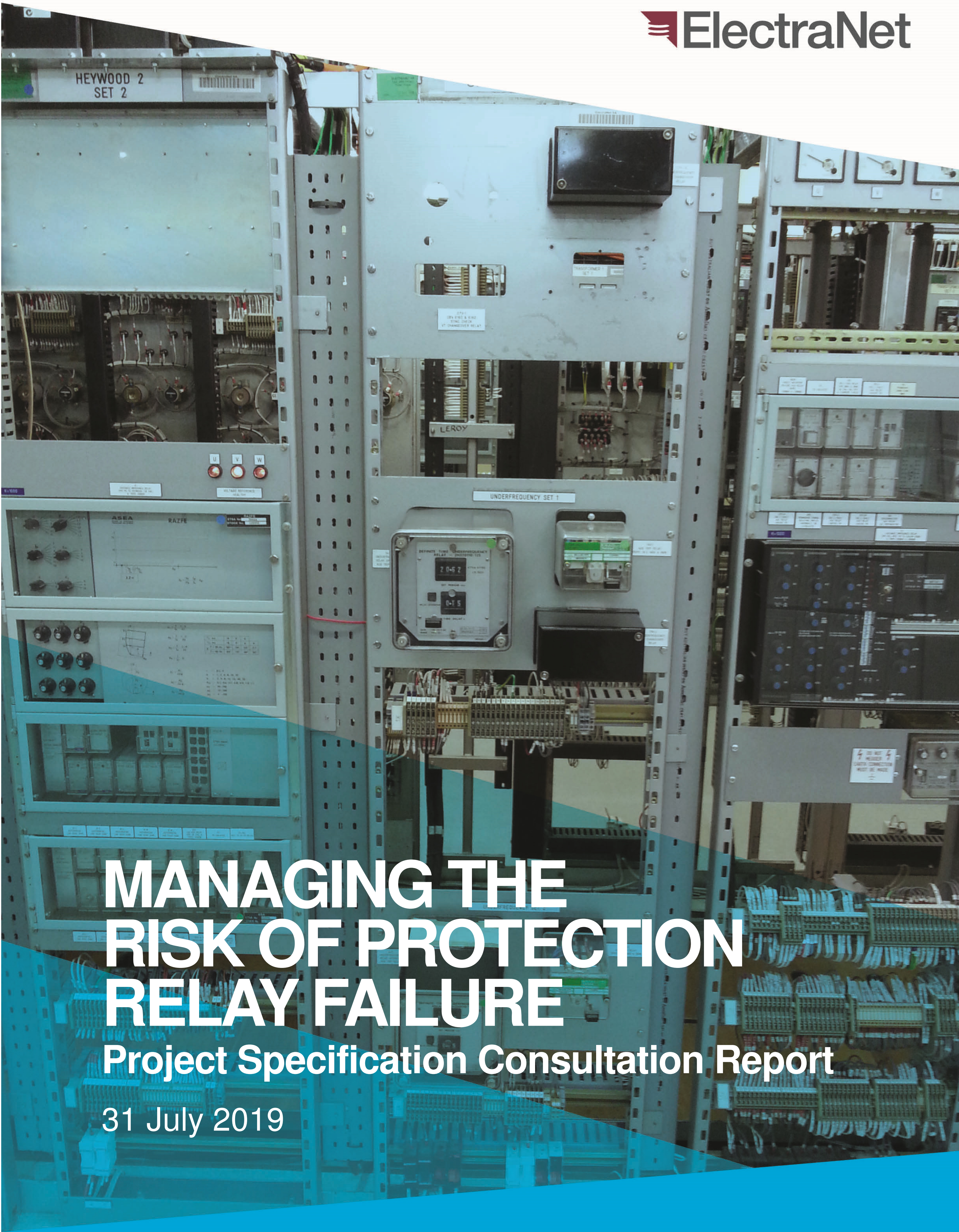

MANAGING THE RISK OF PROTECTION RELAY FAILURE

Project Specification Consultation Report

31 July 2019

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Executive Summary

We propose to replace 376 protection relays to safely and efficiently maintain the South Australian transmission network

This Project Specification Consultation Report (PSCR) identifies the replacement of 376 protection relays across the South Australian electricity transmission network as the most efficient solution to manage the risk of failure of these assets based on their assessed condition and risk.

Protection relays are electricity system components that trip circuit breakers when an abnormality in operating conditions is detected. They protect other components of the electricity system by ensuring faults are cleared within the times specified in the National Electricity Rules (NER).[1]

Protection relays are essential to the task of transmitting electricity – without functional and compliant protection relays electricity infrastructure, electrical workers and the public are at risk.

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

The identified need for this project is to continue to provide 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 protection relays 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 rather is framed based on delivering net benefits to customers.

Nevertheless, meeting the identified need will also help to safely and efficiently maintain compliance with key obligations under the NER. In addition, the Electricity (General) Regulations 2012[2] 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".*

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 protection relays.

This is because protection relays play a specific role in enabling substations to operate and be maintained in a timely fashion, minimising consequential effects on downstream customers.

The estimated capital cost of this option is approximately $27 million, which equates to approximately $120,000 for each of the new relays planned to be installed.

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

2 South Australian Electricity (General) Regulations 2012, Schedule 4—Requirements for earthing and electrical protection systems

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 protection relays play in the transmission of electricity, their relatively low replacement cost (approximately $120,000 per relay) and the range of benefits new protection relays deliver other than reductions in involuntary load shedding.

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

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:

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

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	5.9 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 additional routine corrective maintenance	70 per cent of base estimates	Base estimates	130 per cent of base estimates
Reduced opex associated with developing design standards	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

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

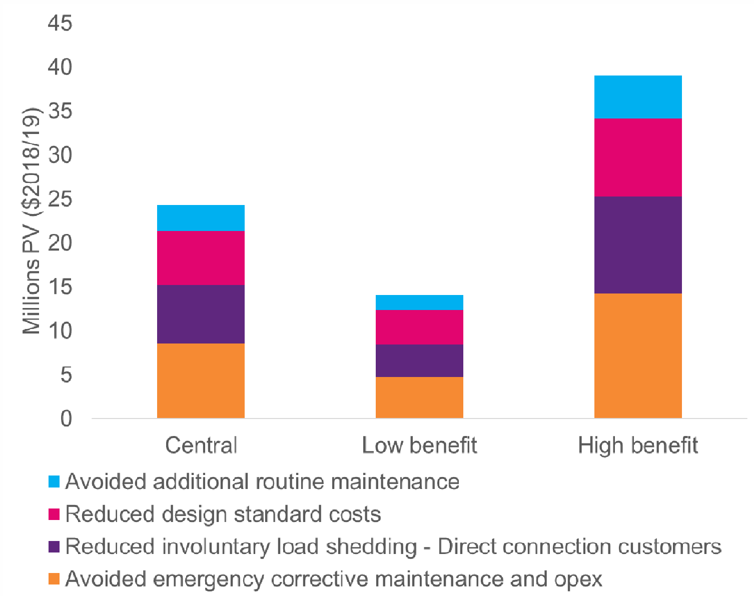
Replacing the identified protection relays as soon as possible is the preferred option[4]

The preferred option that has been identified in this assessment for addressing the identified need is Option 1, i.e. replacing the 376 protection relays between 2019 and 2023.

Most of the expected benefits are derived from the avoided risk of protection relay failure, and the reduced time and cost taken to resolve such failures. Other significant benefits are from offsetting increasing additional routine maintenance costs if the preferred option is not undertaken, as well as avoided labour costs through the creation of design standards and templates.

In addition, the existing electromechanical protection relays unlike the new protection relays, do not have sophisticated communications and diagnostic protocols that are required to support the modern transmission system. While these capabilities will allow ElectraNet to monitor and run its network more efficiently, these additional benefits have not been quantified as part of this RIT-T.

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 $7 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.

We have tested the optimal timing and the sensitivity of this timing to key variables. Under most sensitivities investigated, we find it optimal for Option 1 to be commissioned as soon as possible and the estimated net market benefits relatively robust.

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[4] 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 Project Specification Consultation Report (PSCR) represents the first step in the application of the RIT-T to address the risk of protection relay 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 protection relays, noting that 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 the works involved do not impact on 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 29 October 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 protection relays 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 protection relays.

Subject to submissions received on this PSCR, a Project Assessment Conclusions Report (PACR) is expected to be published by 9 January 2020.

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

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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 protection relays and their role in the wider transmission of electricity in South Australia.

2.1 Background to the identified need

Protection relays are electricity system components that trip circuit breakers when an abnormality in operating conditions is detected. They protect other components of the electricity system by ensuring faults are cleared within the times specified in the National Electricity Rules (NER).[6]

Protection relays at the Davenport substation are illustrated in Figure 2 below. Specifically, Figure 2 shows nine panels of existing electromechanical protection relays (shown by the vertical panels).

Figure 2 - Protection relays at Davenport substation

Protection relays are essential to the task of transmitting electricity – without functional and compliant protection electricity infrastructure, electrical workers and the general public are at risk.

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

Across our transmission network, we have identified 376 protection relays for replacement. These protection relays have a technical life of 40 years and are now predominantly over 38 years old, with some up to 65 years of age.

The protection relays are at or beyond the end of their technical life and therefore are more likely to fail. Furthermore, like-for-like replacements in the event of failures are not feasible due to the absence of technical support from the manufacturers. This will result in significant corrective maintenance costs as new relays will be required rather than components, specifically:

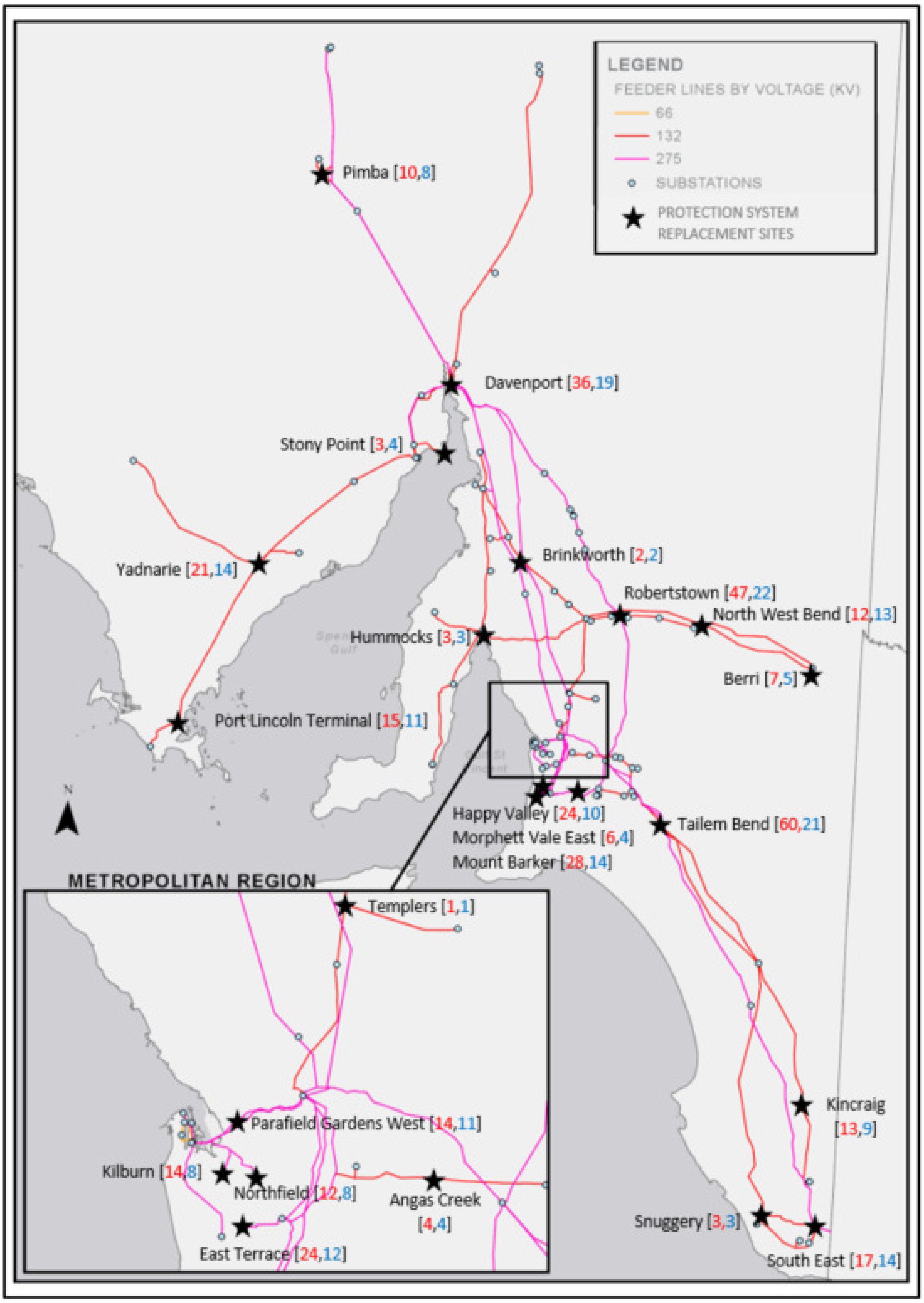
- When manufacturer support is available, the cost of corrective maintenance (replacement on failure) is approximately $106,649; and
- When no manufacturer support is available, the cost of corrective maintenance (replacement on failure) is approximately $200,780

In addition, these electromechanical protection relays do not have the sophisticated communications and diagnostic protocols required to support the modern transmission system.

Modern digital relays can integrate the functionality of several discrete electromechanical relays in one device, simplifying protection design and maintenance. This allows ElectraNet to reduce the number of relays in the system with the 376 identified electromechanical relays to be replaced with 220 digital relays.

Figure 3 illustrates the distribution of the 23 substations where protection relays are being replaced. Specifically, it shows both the number of existing relays identified for replacement (in red) and the number of new modern relays planned to be put in place (in blue) at each substation.

Figure 3 - Location of the protection relays that are being replaced



If the replacement program is not implemented, it is likely that a number of these assets will fail at an increasing rate going forward. This may result in involuntary load shedding on parts of the network and increased costs to replace these assets in a reactive fashion.

In addition, replacing the currently installed protection relays after a failure takes considerably longer as the manufacturing and supply of electromechanical protection relays for transmission networks ceased several years ago. This is due to increased availability and acceptance of more sophisticated electronic and digital relays. Therefore, as a result the spare parts, appropriate skills, facilities to test and repair electromechanical relays are not available or at best rapidly diminishing, and it is no longer possible to effectively test and repair electromechanical relays.

2.2 Description of the identified need for this RIT-T

The identified need for this project is to continue to provide 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 protection relays 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 rather is framed based on delivering net benefits to customers.

Nevertheless, meeting the identified need will also help to safely and efficiently maintain compliance with key obligations under the NER including:

- maintaining system standards and specifically the relevant fault clearance times[7]
- network reliability
  - 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[8]
  - ensuring that for all lines above 66kV the line’s protection system is always available, other than for short periods (not greater than eight hours) whilst maintenance is carried out[9]
- protection systems and the fault clearance times applicable (including the fault clearance times mentioned in maintaining system security).[10]

7 National Electricity Rules, Schedule 5.1a.8
8 Ibid, Schedule 5.1.2.1(a)
9 Ibid, Schedule 5.1.2.1(d)
10 Ibid, Schedule 5.1.9

In addition, the Electricity (General) Regulations 2012[11] 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".*

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 assumptions that underpin the identified need for this RIT-T. Section 6 provides further details on the general modelling approaches applied, including the risk cost modelling framework.

For the purposes of this assessment, the risk cost model focuses on three modes of failure, being:

- failure to trip – where the protection relay does not operate when there is a fault;
- false trip – where the protection relay incorrectly trips when there is no fault, or does not clear the fault within the correct clearance times; and
- repair of a faulty asset – where routine testing identifies a relay that is either not operating or not operating within the specified clearance times.

Each of these failure modes have different characteristics and consequential likelihoods of occurring, as detailed in the section below.

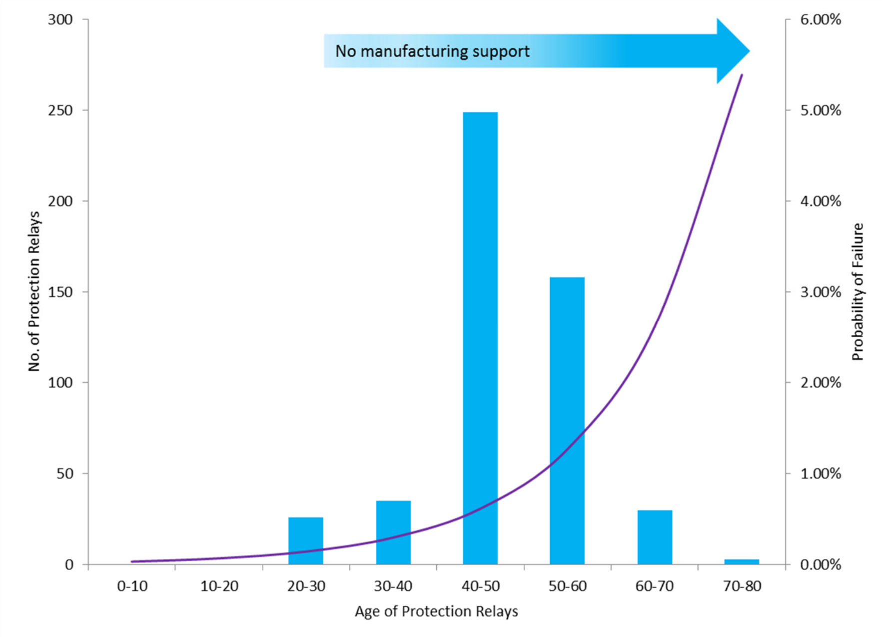
2.3.1 The probability of protection relays failing

The probability of electromechanical protection relays failing is estimated by considering historical data, manufacturers' specifications, industry research and experience. These factors are applied to appropriate probability of failure distribution curves, which show an increase in the probability of failure as the assets increase in age. The probability of failure is modelled based on an exponential equation and increases as the assets age.

A graph of the probability of electromechanical protection asset failures given asset age and the age ranges of the protection assets planned to be replaced is shown below. We have also overlaid the period from which manufacturing support has ceased.

[11] South Australian Electricity (General) Regulations 2012, Schedule 4—Requirements for earthing and electrical protection systems

Figure 4 - Different ages of protection relays being replaced and their probability of failure



The outage assumptions applied in modelling the probability of the different failure modes when a protection relay fails is detailed in Table 2.

As required by the NER[12] most protection relays are duplicated systems (except for non-duplicated auto-reclose relays), and so for an outage to occur, both protection relays need to fail.

Therefore, the probability of an outage is equivalent to the concurrent failure of protection relays (the probability of failure of a protection relay multiplied by itself). Under Option 1, the non-duplicated auto-reclose protection relays will become part of a duplicated system.

12 National Electricity Rules Schedule 5.1.9(c)

Table 2 - Protection relay failure modes and associated likelihoods

Failure Mode	Likelihood of failure mode	Assumed outage duration (hours)		Unserved Energy Load	VCR
		With an electromechanical relay	With a digital relay		
Failure to trip	Additional failure of other (duplicated) protection relay weighted by the probability of the failure mode - 50% for a failure to trip	Dependent on the location of the outage - the time to travel to the site and back.	Dependent on the location of the outage – only the time to travel to the site, as digital relays can be remotely accessed to assess issues.	Dependent on the substation and the location of the relay within substation	Either $37,000 or $6,500 depending on the type of connection lost
False trip	Additional failure of other (duplicated) protection relay weighted by the probability of the failure mode - 25% for a false trip				
Repair of faulty asset	Additional failure of other (duplicated) protection relay weighted by the probability of the failure mode - 25% for a repair of a faulty asset				

2.3.2 The adverse effects resulting from failure of any protection relays

The potential adverse consequences resulting from the occurrence of a protection relay failure include:

- prolonged periods of unserved energy to electricity customers during the time taken to restore (or replace) a failed protection relay;
- increased operating expenditure required to manage the network during an outage event; and
- additional corrective maintenance costs associated with having to repair or replace the protection relay in an unplanned emergency (these costs are identified in section 2.3.3).

2.3.3 The likelihood and cost of negative consequences of a protection relay failure

Our risk cost model therefore models each of these effects that could occur from a protection relay failure. Specifically, the 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 protection relay failures.

Outage durations for protection relays are based on the typical time to repair or replace a protection relay during a failure. The outage duration for electromechanical protection relays is significantly longer than for digital relays due to the sophisticated communication and diagnostic capabilities of digital protection relays, which allows remote interrogation of the device. This is not possible for electromechanical relays, doubling the outage duration.

Additionally, no manufacturing support exists for the electromechanical protection relays being replaced and when they fail they are required to be replaced with new protection relays rather than repaired with components.

In calculating outage costs, the AEMO 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 2017-18.

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 costs associated with unplanned outages and emergency corrective maintenance are material assumptions for undertaking the project. We have therefore included a range of sensitivity tests on these as part of the economic assessment.

Several additional adverse effects have not been captured in our risk cost modelling but are expected to further increase the net market benefits associated with Option 1. These additional adverse effects following a relay failure include:

- Potential widespread consequential outages due to non-credible contingencies;
- Deferral of planned outages for operational and capital works;
- Additional significant safety risks to members of the public and industry workers if a protection relay failure coincided with an asset failure, such as a recent event of a tractor destroying a transmission pole; and
- Significant bushfire risks if protection failures coincided with a line hardware failure which resulted in a live conductor being on the ground.

Section 7 demonstrates these additional benefits would not change the preferred option and so they are not considered material in the context of this RIT-T.

2.3.4 Replacing the identified relays also offsets additional routine maintenance costs

In addition to the benefits associated with reducing the adverse effects resulting from failure of any protection relays, replacing the identified protection relays will also offset increasing routine maintenance costs.

Specifically, digital protection relays are continuously monitored remotely, unlike the existing electromechanical relays that require on-site inspection and testing by field staff to determine if they are operating within the standards. Electromechanical relays are typically inspected every four years but, under the base case, are assumed to be inspected increasingly frequently as the assets are already at the end of their technical lives and would therefore be more likely to fail.

2.3.5 New protection relays facilitate a range of modern network diagnostics

The installation of new modern protection relays that are able to be monitored remotely also allow for a range of continuous information to be provided to ElectraNet. This includes:

- self-testing and communication to supervisory control systems;
- monitoring of contact inputs;
- metering; and
- waveform analysis.

This will allow ElectraNet to monitor and run its network more efficiently than currently. The benefits of these greater network diagnostics have not been quantified as part of this RIT-T.

3. Potential credible options to address the identified need

There is only one technically feasible option, which is to replace the end-of-life protection relays. This is because protection relays play a specific and important role in enabling substations to operate and to be maintained in a timely fashion, minimising any consequential effects on downstream customers. Further, the form and capabilities of protection schemes and the associated protection relays are prescribed in the NER (as noted in section 2.2 above).

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] In addition, all works are assumed to be completed in accordance with the relevant standards, with protection relays being replaced with minimal modification to fit to the substation.

3.1 Option 1 – Targeted replacement of protection relays by 2023

Option 1 involves replacing the 376 identified electromechanical protection relays in the 2019-2023 period with 220 modern digital equivalents.

The modern protection relays are able to be continuously remotely monitored, and so no additional routine maintenance is required for these assets. In fact, as outlined in section 0 above, Option 1 offsets increasing routine maintenance costs compared to the base case (which assumed that there will be additional on-site inspection and testing of the assets that increases with time).

The estimated total capital cost of this option is approximately $27 million. This equates to approximately $120,000 for each of the 220 new relays planned to be installed.

It is estimated that onsite, the construction time for each relay is around 1 to 2 weeks and that the entire program of replacement can be completed in around 3 to 4 years. We estimate that all relays could be replaced and commissioned by 2023 under this option.

The additional routine maintenance costs required to monitor and test the aging electromechanical relays is expected to trend to zero between 2021 and 2023 (and be zero from then onwards). This is due to the ability to remotely monitor digital protection relays.

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 protection relays does not lend itself to any solution other than to replace the protection relays 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.

[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 protection relays. 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 the coming years. Therefore, this is not considered to be an economically feasible option.

Another option could be to consider implementing a spares program. However, the current condition of the electromechanical relays are not sufficient to create spares. Moreover, the new digital relays have fundamental differences in functionality compared to electromechanical relays and are better able to support the changing conditions of the network by being able to provide modern network diagnostics. Therefore, this is not considered to be an economically feasible option.

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

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 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 material inter-network impacts associated with Option 1.

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 protection relays play in the transmission of electricity. Furthermore, the replacement cost is relatively low (approximately $120,000 per relay) and there are various benefits outside reductions in involuntary load shedding in replacing the protection relays (i.e. those outlined in section 2 above).

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

Protection relays 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 protection relays.

A network support option that avoids replacement of protection relays 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 the following substations are likely to incur unserved energy and/or require generation support following the failure of a protection relay.

Table 3 - Substations at risk of unserved energy and/or requiring generation support under the base case

Davenport	Stony Point	Templers	Mount Baker
Kincraig	Hummocks	North West Bend	Pimba

The average load for each of these substations is approximately 24.4 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 restore (or replace) a failed protection relay. 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 protection relays 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]

The bulk of the 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). These include avoided risk costs as described above.

Only unserved energy of these avoided costs, 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/MWh 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 does not address network constraints between competing generating centres and is 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:

- changes in fuel consumption arising through different patterns of generation dispatch;
- changes in voluntary load curtailment (since there is no impact on pool price);

[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.

- 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 4 - 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 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 relays 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 15-year period from 2019 to 2033, which considers the size, complexity and expected life of each option to provide a reasonable indication of its cost.

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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.

The digital protection relays have asset lives of 15 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 15-year assessment period.

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.

In 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 more extreme pessimistic set of assumptions, which represents a lower bound on potential market benefits that could be realised; and
- a 'high benefits' scenario – reflecting a more extreme optimistic set of assumptions, which represents an upper bound on potential market benefits that could be realised.

Table 5 summarises the key assumptions making up each scenario.

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[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/electranet-determination-2018-23/final-decision

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

Given that the low and high benefits scenarios are more unlikely to occur the scenarios have been weighted accordingly; 25% - low benefits scenario, 50% - central benefits scenario, and 25% - high benefits scenario.[26]

Table 5 - 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[27]	8.95 per cent	5.9 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 additional routine corrective maintenance	70 per cent of base estimates	Base estimates	130 per cent of base estimates
Reduced opex associated with developing design standards	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] In accordance with paragraph 4(a) of the RIT-T.

[27] 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

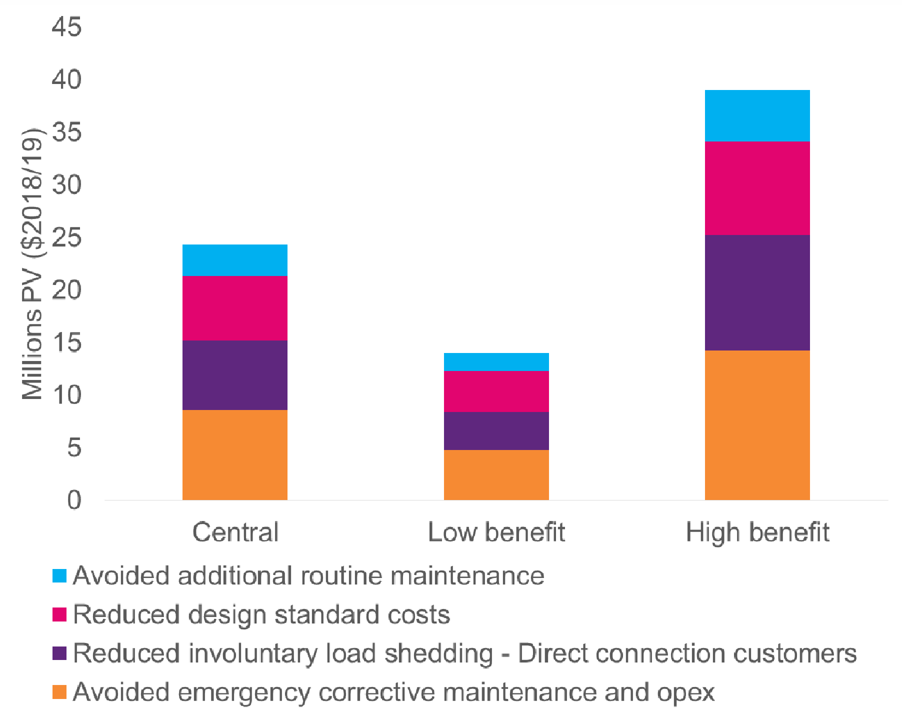
The table below summarises the gross benefit estimated for Option 1 relative to the 'do nothing' base case in present value terms. The gross market benefit has been calculated for each of the three scenarios outlined in Table 6.

Table 6 - Estimated gross market benefit for each option, PV $m

Option	Low benefits scenario	Central scenario	High benefits scenario
Option 1 – Planned replacement of protection relays by 2023	14.0	24.3	39.1

The figure below provides a breakdown of benefits and shows that the majority of benefits are derived from the avoided risk of protection relay failure and the reduced time taken to resolve such failures. There are also significant benefits from offsetting the increasing additional routine maintenance costs if Option 1 is not undertaken, as well as avoided labour costs through the creation of design standards and templates.

Figure 5 - Breakdown of present value gross economic benefits of Option 1



7.2 Estimated costs for each credible option

Table 7 summarises the capital costs of Option 1, relative to the base case, in present value terms for the different scenarios as described in Table 5.

Table 7 - Estimated capital cost for each option, PV $m

Option	Low benefits scenario	Central scenario	High benefits scenario
Option 1 – Planned replacement of protection relays by 2023	-23.8	-18.8	-13.2

7.3 Net present value assessment outcomes

Table 8 summaries the net market benefit in NPV terms for Option 1 across the three scenarios, as well as on a weighted basis. The net market benefit is the gross benefit (as set out in section 7.1) minus the cost (as outlined in section 7.2), all expressed in present value terms.

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

Table 8 - Estimated net market benefit for each option, PV $m

Option	Low benefits scenario	Central scenario	High benefits scenario	Weighted
Option 1 – Planned replacement of protection relays by 2023	-9.8	5.5	25.9	6.8

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. Similarly, the high benefits scenario is also relatively unlikely.

As outlined in Table 5, the low scenario is based on including 30 per cent higher capital costs, a commercial discount rate of 8.64 per cent and 70 per cent lower benefits (across all types of benefits).

We have been conservative in our approach, not including those additional adverse effects as discussed in section 2.3.3 that would be reduced if Option 1 was undertaken.

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 Figure 7).

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 in which the present value of the monetised service costs exceeds the present value of the replacement project costs,[28] 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.

Figure 6 outlines the impact on the optimal year to commence the program, 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. For each sensitivity listed in the legend, the assumption listed is the one that is being tested in that specific sensitivity (all other assumptions are the same as they are in the central case).

The optimal commencement date is found to be in the year 2019, i.e. as soon as possible, for a significant majority of the sensitivities investigated (as illustrated in Figure 6 by the grey bars). Option 1 begins to deliver economic benefits before the full capital replacement program is completed, i.e. in 2023, demonstrating that commencing the Option 1 capital program immediately will maximise net economic benefits.

Furthermore, although Figure 6 illustrates that the optimal commissioning date is found to be as soon as possible, the four exceptions to this are for the following sensitivities (shown in Figure 6 by the non-grey bars):

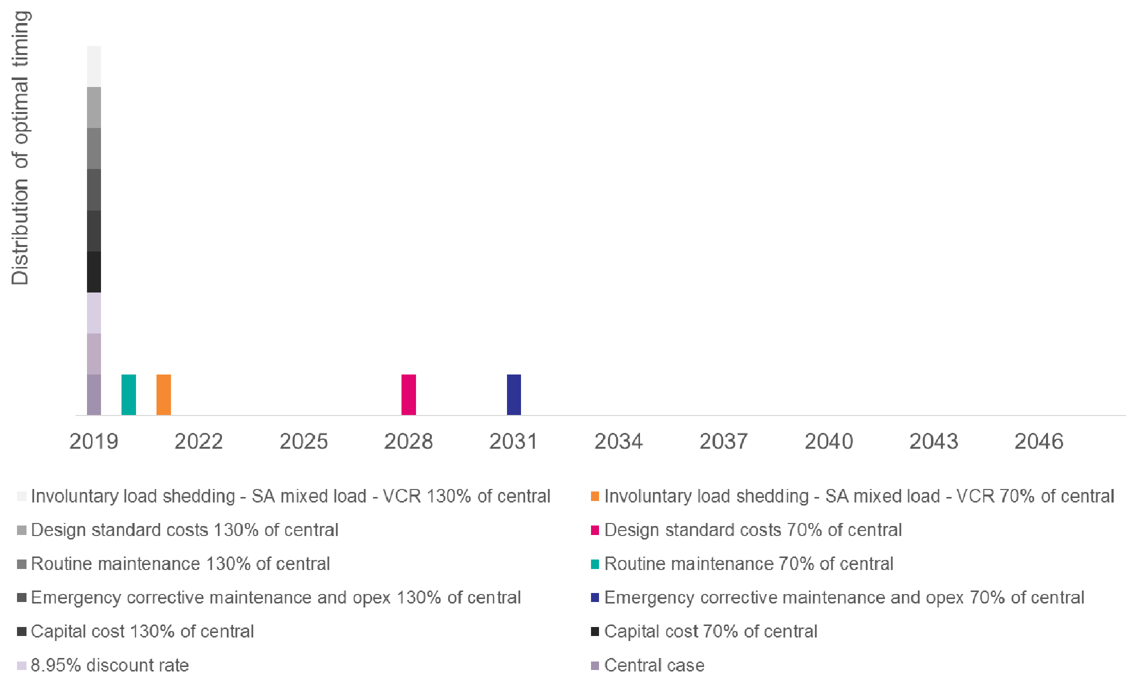
- avoided additional routine maintenance when decreased to 70 per cent of the central value (optimal timing at 2020);
- reduced involuntary load shedding (SA mixed VCR) when decreased to 70 per cent of the central value (optimal timing at 2021);
- design standard benefits when decreased to 70 per cent of the central value (optimal timing at 2028); and
- avoided emergency corrective maintenance costs when decreased to 70 per cent of the central value (optimal timing at 2031).

These four sensitivities delay the optimal timing of the investment as they reduce the benefits that are accrued relatively earlier in the modelling period. However, we find that a large majority of sensitivities indicate that the optimal timing is to commence the investment now, and so, on balance, we consider that the investment is required as soon as possible.

Please note that Figure 6 shows the optimal year to *commence* the program of replacement, whilst recognising that it will take five years to complete the replacement works (i.e., the earliest all protection relays can be replaced is 2023).

[28] 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).

Figure 6 - 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 reviewed the consequences for the credible option of 'getting it wrong' if the key underlying assumptions are not accurate.

The six figures below illustrate the estimated net market benefits for each option if the six 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 are found to be strongly positive.

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.

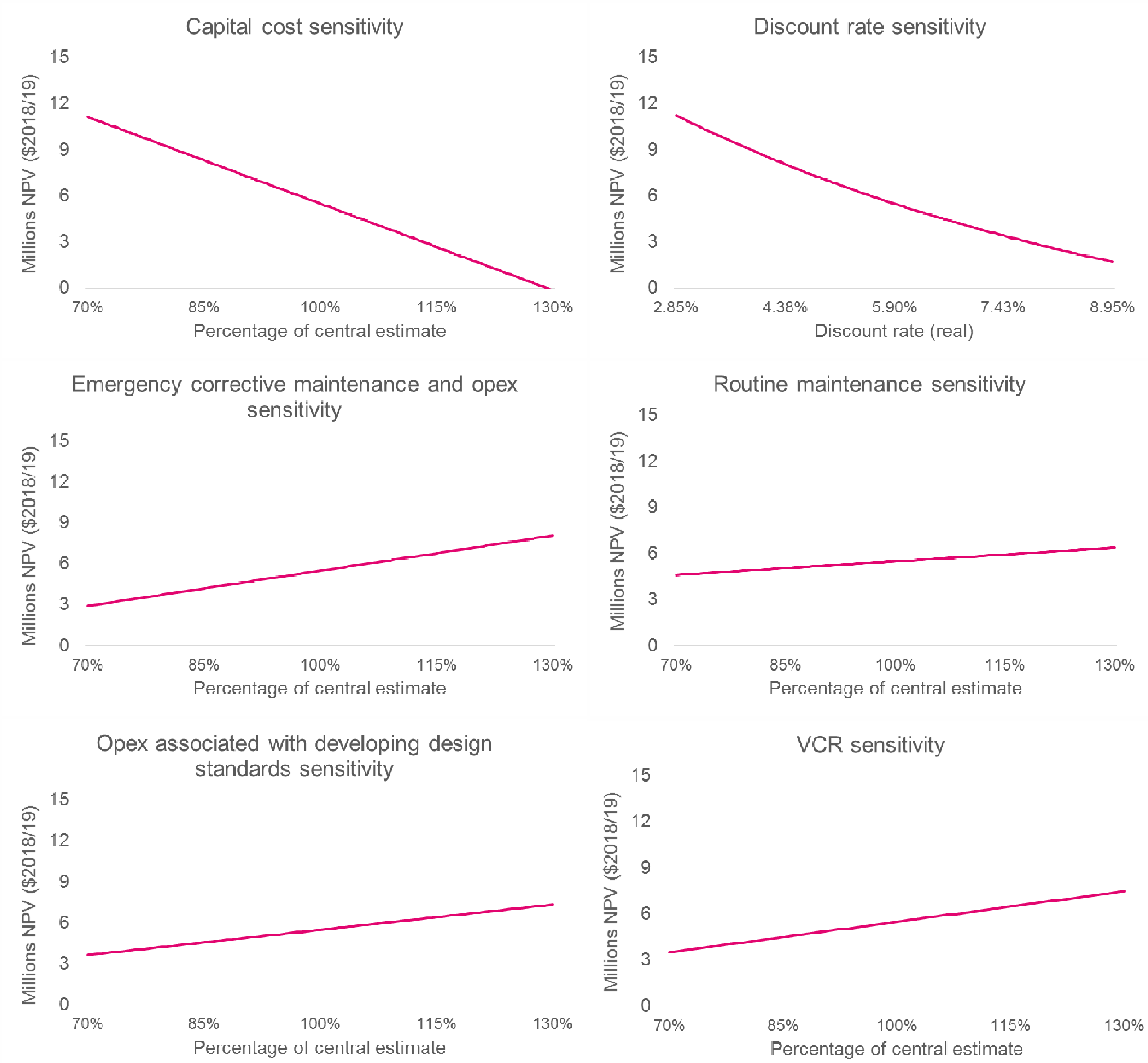
Table 9 - Threshold values for key assumptions for Option 1 to no longer have positive net market benefits

Key variable/parameter	Threshold value
Capital cost	129% of central estimate
Discount rate	10.96%
Emergency corrective maintenance	35% of central estimate
Failure rate of protection relays	63% of central estimate

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. We find that for additional routine maintenance costs, opex associated with developing design standards and the value of customer reliability that these could decrease to zero and Option 1 would still have positive net market benefits.

While we find that the results are most sensitive to the underlying capital costs, we consider that the amount by which costs would need to be increased by in order for there to be negative expected benefits (29 per cent) is highly unlikely since these costs have recently been reviewed and considered to be estimated at a higher level of accuracy than +/- 30 per cent. In addition, as set out in section 2.2, Option 1 is being progressed both in terms of the net market benefits it is expected to deliver as well as to substantially reduce the risk of non-compliance with a range of obligations under the NER.

Figure 7 - 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 protection relays by 2023. This option is described in section 3 and is estimated to have a capital cost of $27 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 $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 this assessment is exempt from the requirement for a PADR under NER clause 5.16.4(z1) based on 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.[29]

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

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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 122.

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

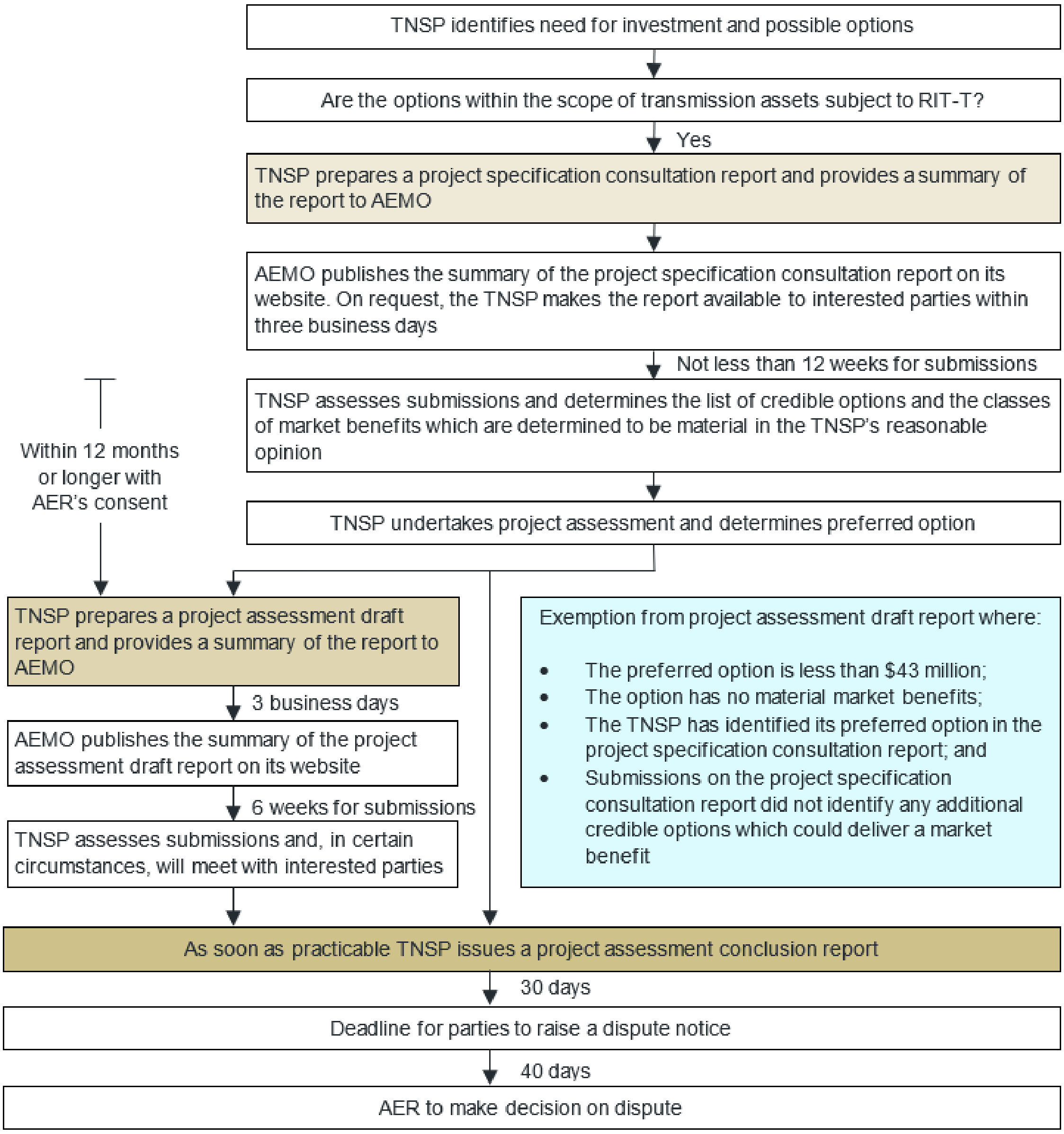
All laws, regulations, orders, licences, codes, determinations and other regulatory instruments (other than the NER) which apply to Registered Participants from time to time, including those applicable in each participating jurisdiction as listed below, to the extent that they regulate or contain terms 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 8 - The RIT-T assessment and consultation process



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