ElectraNet

Managing the Risk of Protection Relay Failure 2024-2028

Project Specification Consultation Report

14 JUNE 2024

EXECUTIVE SUMMARY

We are proposing to replace around 106 protection relays at 6 substations to maintain safe and reliable electricity supply to customers.

This Regulatory Investment Test for Transmission (RIT-T) Project Specification Consultation Report (PSCR) identifies the need to replace 106 protection relays at six substations as the preferred solution to manage the risk that these assets will fail.

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 stipulated in the National Electricity Rules (NER).[1] The protection systems in question for this PSCR have reached the end of their technical lives and they are no longer supported by the manufacturer. There is an increased likelihood that several of these protection relays will fail in the coming years resulting in unplanned customer outages.

Protection relays are essential to the task of transmitting electricity, without functional and compliant protection relays electricity infrastructure, electrical workers and the general 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 past the end of their technical lives based on their condition.

We have classified this RIT-T as a 'market benefits' driven RIT-T as it is being progressed to manage the risk of asset failure and thereby deliver positive net benefits to customers.

A full cost benefit assessment has been undertaken, comparing the risk cost reduction benefits of protection relays replacement with the cost of a base case 'do nothing' option, together with options considered but not being progressed.

Protection Relay replacement is the only credible option.

There is only one economically feasible option, which is to replace the end-of-life protection relays at the identified substations.

Two replacement timing options are considered. Option 1 which is to undertake the protection relay replacement in the current regulatory period between 2024 and 2028 and Option 2 which considers a five-year delay.

The estimated capital cost of this option is approximately $16.3 million.

This is below the threshold requiring us to complete a Project Assessment Draft Report (PADR) under NER clause 5.16.4(z1). This RIT-T is therefore exempt from the need to produce a PADR.

There is no feasible role for non-network option in addressing the identified need for this RIT-T.

ElectraNet does not consider that a non-network option can meet the identified need for this RIT-T. This is due to the unique and specific role that the identified protection relays play in the transmission of electricity, their relatively low replacement cost and the range of benefits new protection relays deliver other than reductions in involuntary load shedding.

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

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

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 case 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.

Table 1 - Summary of the three scenarios

Key variable/parameter	Low benefits scenario	Central scenario	High benefits scenario
Capital costs	130 per cent of base case estimate	Base case estimate	70 per cent of base case estimate
Commercial discount rate[2]	3.0%	7.0%	10.5
Involuntary Load Shedding cost	70 per cent of base case estimates	Base case estimates	130 per cent of base case estimates
Emergency Replacement Cost	70 per cent of base case estimates	Base case estimates	130 per cent of base case estimates
Substation Asset Damage Cost	70 per cent of base case estimates	Base case estimates	130 per cent of base case estimates
Risk Cost	70 per cent of base case estimates	Base case estimates	130 per cent of base case estimates

Replacing the identified protection relays as soon as possible is the preferred option[3]

The preferred option that has been identified in this assessment for addressing the identified need is Option 1, i.e. replacing the 106 protection relays at six substations between 2025 and 2028.

Most of the expected benefits are derived from the avoided risk of unplanned outages and service interruptions, and cost of asset failure.

Other significant benefits are from the reduced routine maintenance costs that are likely to be incurred if the protection relays are replaced.

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

[3] 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 the preferred option

On a weighted basis (i.e., weighted across the three scenarios investigated), the preferred option is expected to deliver approximately $25.7 million.

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. Under most sensitivities investigated, we find it optimal for the preferred option to be undertaken as soon as possible and the estimated net market benefits to be robust.

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Glossary

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ALARP	As Low as Reasonably Practicable
ETC	Electricity Transmission Code
NPV	Net Present Value
NEM	National Electricity Market
NER	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
VCR	Value of Customer Reliability

1. Introduction

This Project Specification Consultation Report (PSCR) is the first step in the application of the Regulatory Investment Test for Transmission (RIT-T) addressing the risk of failure of 106 protection relays at six substations located across 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

The National Electricity Rules (NER) require the application of the RIT-T to replacement capital expenditure where there are credible options costing more than $7 million.[4]

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 Integrated System Plan (ISP) 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 Friday, 6 September 2024. 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 published, please clearly specify this at the time of making it. Subject to submissions received on this PSCR, a Project Assessment Conclusions Report (PACR) is expected to be published in due course.

Further details in relation to this project can be obtained from: consultation@electranet.com.au

[4] NER clause 5.15A.1(c) states that the purpose of the RIT–T is to: identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is a net economic cost) to the extent the identified need is for reliability corrective action or the provision of inertia network services required under clause 5.20B.4 or the provision of system strength services required under clause 5.20C.3.

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

This section outlines the identified need and 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

The 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 stipulated in the National Electricity Rules (NER).[5]

An example of protection relays at New Osborne substation that are planned to be replaced is illustrated in Figure 2.

Figure 2 – Protection relays at the New Osborne substation identified for replacement.

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

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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.

Across our transmission network, we have identified 106 protection relays for replacement located at six substations (refer Figure 3 - Location of the protection relays identified for replacement.). The condition of these protection relays is such that they require replacement within 2024-2028 period. These protection relays have a standard technical life of 20 years and are now predominantly over 23 years old, with some up to 54 years of age.

These 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 and availability of spares. This will result in significant corrective maintenance cost to reactively replace the failed electromechanical relays with a modern digital relay in an unplanned emergency situation.

In addition, the replacement of electromechanical relays with digital relays provides additional functionality to support sophisticated communications and diagnostic protocols that are required for management of a modern transmission system. While these capabilities will allow us to monitor and run its network more efficiently, these additional benefits have not been quantified as part of this RIT-T. Furthermore, the modern digital relays can integrate the functionality of several discrete electromechanical relays in one device, simplifying protection design and maintenance. This allows us to reduce the number of relays in the system with the 106 identified relays to be replaced with 58 digital relays.

Figure 3 - Location of the protection relays identified for replacement.

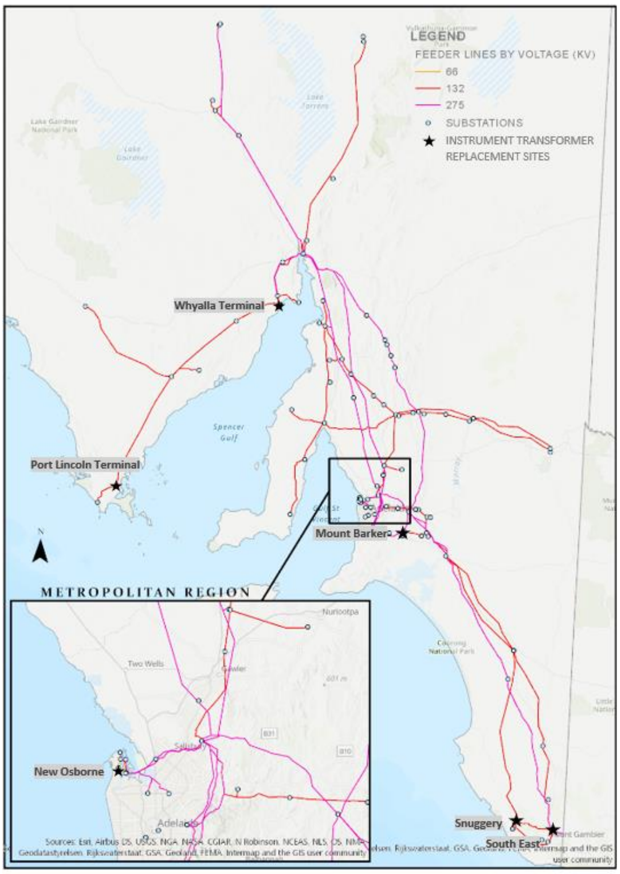

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Table 2 below provides the details about the protection relays that are planned to be replaced including the locations and quantities.

Table 2 – Protection relays planned for replacement.

Substation	Quantity
New Osborne	40
Port Lincoln Terminal	4
Snuggery	12
South East	36
Whyalla Terminal	4
Mount Barker	10
Total	**106**

If the protection relays in question are not replaced, it is increasingly likely that they will fail with the following two possible consequences:

- Potential for unplanned outages resulting in unavailability of parts of the network and possible supply interruption; and
- Increased costs to replace these assets upon failure.

2.2. Description of the identified need for this RIT-T

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

We assess the condition of all our protection relays as part of our ongoing asset management processes. There is an increased likelihood that several of the 106 protection relays will fail in coming years given their current age and condition. Failure could result in unplanned customer outages and increase cost to reactively replace upon failure.

Further, this replacement program will substantially reduce the risk of non-compliance with a range of obligations under the NER and other jurisdictional instruments. Key among these are our compliance obligations under the NER:

- *to maintain the system standards (S5.1a),*
- *network reliability (S5.1.2),*
- *stability of our network (S5.1.8)*
- *appropriate standards of fault clearance times (S5.1a.8), and*
- *protection systems (S5.1.9).*

The Electricity (General) Regulations 2012[6] also requires that:

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

- *"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".*

These obligations have been taken into account in quantifying the benefits of this project which is classified as a 'market benefits' RIT-T. It is being progressed to deliver positive net benefits to customers by managing the risk of asset failure.

A full cost benefit assessment has been undertaken, comparing the risk cost reduction benefits of asset replacement options with the cost of those options.

2.3. Assumptions underpinning the identified need

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

For the purposes of this assessment, the risk cost model focuses on 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
- faulty asset – where routine testing identifies a relay that is either not operating or not operating within the specified clearance times.

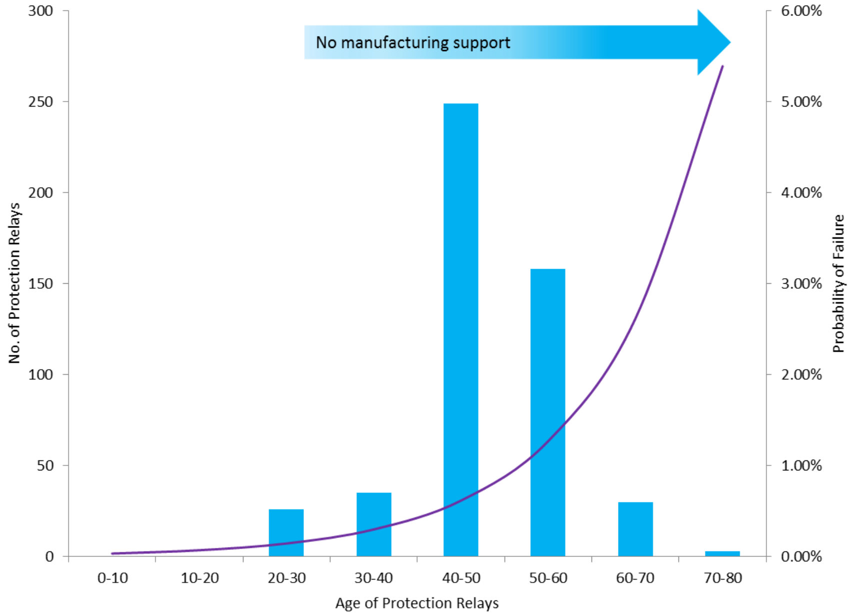
Each of these failure modes have different characteristics and consequent likelihoods of occurring, as is detailed in the section below.

2.3.1. The probability of failure

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.

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



The outage assumptions applied in modelling and probability of the different failure modes when protection relay fails is detailed in Table 3.

As required by the NER[7] most protection relays are duplicated systems 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).

Table 3 - 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 of 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	$52,382
False trip	Additional failure of other (duplicated) protection relay weighted by the probability of the failure mode of 25% for a false trip				
Repair of faulty asset	Additional failure of other (duplicated) protection relay weighted by the probability of the failure mode of 25% for a repair of a faulty asset				

[7] National Electricity Rules Schedule 5.1.9(c)

2.3.2. The consequences of failure

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 our network during an outage event; and
- additional corrective maintenance costs associated with having to repair or replace the protection relay in an unplanned emergency situation (these costs are identified in section **Error! Reference source not found.**).

2.3.3. The likelihood and cost of protection relay failure

Our risk cost model analyses the consequences listed in section 2.3.2. It estimates the 'likelihood of consequence' (LoC) and 'cost of consequence' (CoC) of protection relay failures.

Outage durations for protection relays are based on the typical time to repair or replace a protection relay following 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 allow remote interrogation of the device. Whereas this is not possible for electromechanical relays, doubling the outage duration. Additionally, no manufacturing support exists for the electromechanical protection relays and when they fail, they are required to be replaced with new protection relays rather than repaired with components.

Outage cost is based on the Australian Energy Regulator's (AER) estimated Value of Customer Reliability (VCR) which is expressed in dollars per kilowatt-hour (kWh) and reflect the value different customer types place on reliable electricity supply. All loads are based on a representative load trace taken from 2019-20 escalated to 2023 dollars based on the Consumer Price Index for that year.

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.

Several additional adverse effects and benefits have not been captured in our risk cost model but would be expected to further increase the net market benefits associated with Option 1 and are listed below.

Additional adverse effects following a relay failure include:

- Potential widespread consequential outages due to noncredible contingencies;
- Deferral of planned outages for operational and capital work;
- 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.

Additional benefits of installation of modern digital relays include:

- Reduction in routine maintenance as they are continuously monitored, therefore reducing the need for onsite inspection; and
- Access to continuous network information, such as;
  - self-testing and communication to supervisory control systems;
  - monitoring of contact inputs;
  - metering; and
  - waveform analysis.

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.

3. Potential credible options to address the identified need

There is only one economically feasible option, which is to replace the identified protection relays.

We have however investigated different assumed timings for this work in order to determine the optimal timing. This assessment is presented in section 7.

The option is technically and economically feasible and able to be implemented in sufficient time to meet the identified need.[8]

3.1. Option 1 – Planned replacement of protection relays by 2028

Option 1 involves replacing the 106 protection relays at the six substations as identified in section 2.1.

Replacing these protection replays is planned to occur between 2025 and 2028.

ElectraNet has prepared an estimate of the cost of implementing this option which is $16.3 million. This is a Class 4 estimate prepared in accordance with the Australian Association of Cost Engineer's 'class 4' estimate categorisation. As such it was produced through a desktop review based on a scope prepared by ElectraNet's asset engineering team. It has an estimating range of -30% to +50%.

The additional routine maintenance costs required to monitor and test the aging electromechanical relays is expected to trend to zero between 2025 and 2028 (and be zero from then onwards). This is due to the ability to remotely monitor digital protection relays.

The estimated construction time is approximately 3 years. We estimate that all the protection relays could be addressed by 2028 under this option.

3.2. Options considered but not progressed

We have not identified other credible options that would meet the identified need.

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

We have considered whether the credible option will have a material inter-regional impact.[9].

By reference to AEMO's screening test for an inter-network impact[10], a material inter-regional impact arises 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.

None of these criteria are satisfied for the project discussed here. Therefore, ElectraNet does not consider there are any associated material inter-network impacts.

[8] In accordance with those identified in section **Error! Reference source not found.**.

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

[10] 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

ElectraNet does not consider that a non-network option can provide a solution that is both technically and economically feasible.

For clarity, a non-network solution must be capable of providing the same services at a lower long run cost as Option 1, which is to replace the 106 protection relays at the six substations.

Any non-network solution that avoids replacement of protection relays in scope must be able to replicate the functionality, capacity, and reliability of the entire substation that these protection relays are located.

We are not aware of non-network options that are capable of doing this, but invite submissions on this point from proponents of such options if they do exist.

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.[11]

The bulk of the benefits associated with the preferred option 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.

Of these avoided costs only unserved energy due to involuntary load shedding is considered a market benefit category under the NER.

5.1. Avoided involuntary load shedding is the only relevant market benefit

The only relevant market benefit for this RIT-T relates to changes in involuntary load shedding. The expected unserved energy under the base case, which is avoided under the preferred option, has been estimated as part of our risk cost modelling.

5.2. Market benefits relating to the wholesale market are not material

The AER has recognised that a number of classes of market benefits will not be material in a RIT-T assessment if the credible options considered will not have an impact on the wholesale market. In this case the impacts do not need to be estimated.[12]

The preferred option would not affect network constraints between competing generating centres so it would not change dispatch outcomes or wholesale market prices.

Therefore, we consider the following classes of market benefits to be immaterial 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.

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[11] 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 5.16.2(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.

[12] AER, *Regulatory Investment Test for Transmission Application Guidelines*, August 2020, p. 29.

We consider that none of these are material for this RIT-T assessment for the reasons set out in Table 4.

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	The preferred option 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.[13] 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 the preferred option maintains the current network capacity at the same location, there are not expected to be any differences in network losses.

[13] AER, *Regulatory Investment Test for Transmission Application Guidelines*, August 2020, p. 52.

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 reduction associated with replacing the identified protection relays.

The 'risk cost reduction' has been calculated as the product of:

- Probability of Failure, which is the probability of a failure occurring based on asset failure history information and industry data;
- Likelihood of Consequence, which is the likelihood of an adverse consequence of the failure event based on historical information and statistical factors; and
- Cost of Consequence, which is the estimated cost of the adverse consequence.

These three variables allow the expected risk cost reduction benefit to be quantified and an assessment against the cost of the project to be undertaken. The risk cost reduction benefit is the difference between risk costs incurred under the base case and the preferred option.

The approach we apply to quantifying risk was presented as part of our Revenue Proposal for the 2024-2028 regulatory control period. In its Draft Decision on that proposal, the AER found it to be consistent with good industry practice and to generally reflect reasonable inputs and assumptions.[14]

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.[15]

6.2. The discount rate and assessment period

The RIT-T analysis has been undertaken over a 12-year period from 2024 to 2036. This considers the size, complexity and expected life of each option to provide a reasonable indication of its cost.

While the modern digital protection relays have asset lives greater than 12 years, we have taken a terminal value approach to incorporating capital costs in the assessment, which ensures that the capital cost of each option is appropriately captured in the 12-year assessment period.

We have adopted a real, pre-tax discount rate of 7.0 percent as the central assumption for the analysis presented in this report, consistent with AEMO's most recent Inputs, Assumptions and Scenarios Report.[16] 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.

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[14] AER, *ElectraNet transmission determination 2023 to 2028*, Draft Decision, Attachment 5 – Capital expenditure, September 2022

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

[16] AEMO, Inputs, Assumptions and Scenarios Report, July 2023, p. 123.

The RIT-T requires that sensitivity testing be conducted on the discount rate and that the discount rate scenarios from AEMO's ISP Inputs Assumptions and Scenarios Report should be applied.[17]

We have therefore tested the sensitivity of the results to changes in this discount rate assumption, and specifically to the adoption of a lower bound discount rate of 3.0 percent, and an upper bound discount rate of 10.5 percent.[18]

6.3. Description of reasonable scenarios

A RIT-T analysis is required to incorporate several 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.

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.

Given that the low and high benefits scenarios are more unlikely to occur the scenarios have been weighted accordingly; 33% - low benefits scenario, 33% - central benefits scenario, and 33% - high benefits scenario.[19]

Table 5 - Summary of the three scenarios

Key variable/parameter	Low benefits scenario	Central scenario	High benefits scenario
Capital costs	130 per cent of base case estimate	Base case estimate	70 per cent of base case estimate
Commercial discount rate[20]	3.0%	7.0%	10.5
Involuntary Load Shedding cost	70 per cent of base case estimates	Base case estimates	130 per cent of base case estimates
Emergency Replacement Cost	70 per cent of base case estimates	Base case estimates	130 per cent of base case estimates
Substation Asset Damage Cost	70 per cent of base case estimates	Base case estimates	130 per cent of base case estimates
Risk Cost	70 per cent of base case estimates	Base case estimates	130 per cent of base case estimates

17 AER, *Regulatory Investment Test for Transmission*, August 2020 p. 6.

18 AEMO*, Inputs, Assumptions and Scenarios Report*, July 2021, p. 104.

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

20 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 and the option to delay the project by 5 years. The assessment compares these options against a 'do nothing' base case option.

7.1. Gross benefits for each credible option

Table 6 below summarises the gross benefit estimated for the preferred option, Option 1 replacing the identified protection relays by 2028 and Option 2, delaying replacement of the identified protection relays by 5 years, 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 2028	27.9	32.7	36.0
Option 2- Delay replacement of protection relays by 5 years	24.4	27.2	28.4

Figure 5 below provides a breakdown of benefits. It shows that the benefits are derived from the reduced cost risk of protection relays failure and the reduced time taken to resolve such failures.

Figure 5 - Breakdown of present value gross economic benefits of the preferred option 1

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7.2. Estimated costs for each credible option

Table 7 summarises the capital costs of the preferred Option 1 and Option 2, 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 2028	-7.0	-6.9	-5.3
Option 2- Delay replacement of protection relays by 5 years	-2.9	-2.6	-1.8

7.3. Net present value assessment outcomes

Table 8 summarises the net market benefit for preferred Option 1 and Option 2 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 compared to Option 2 on a probability-weighted basis in all scenarios.

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

Option	Low benefits scenario	Central scenario	High benefits scenario	Weighted
Option 1 – Planned replacement of protection relays by 2028	20.9	25.7	30.7	25.7
Option 2- Delay replacement of protection relays by 5 years	21.6	24.6	26.6	24.2

We have been conservative in our approach by not including the additional benefits of this option discussed in section 3.3.

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 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 and optimal timing.

Our assessment demonstrates that there is minimal difference between Option 1 replacing the identified protection relays by 2028 as compared to Option 2 of delaying the replacement by 5 years. Both options are strongly NPV positive compared to the base case of 'do nothing' option.

Option 1 is our preferred option which is to replace the identified protection relays by 2028. This option enables us to comply our obligations, detailed in Section 2.2, to manage the network risk ALARP and to comply with South Australia's Workplace Health and Safety Act to manage SFARP the safety risk to personnel and the public in the event of a catastrophic failure.

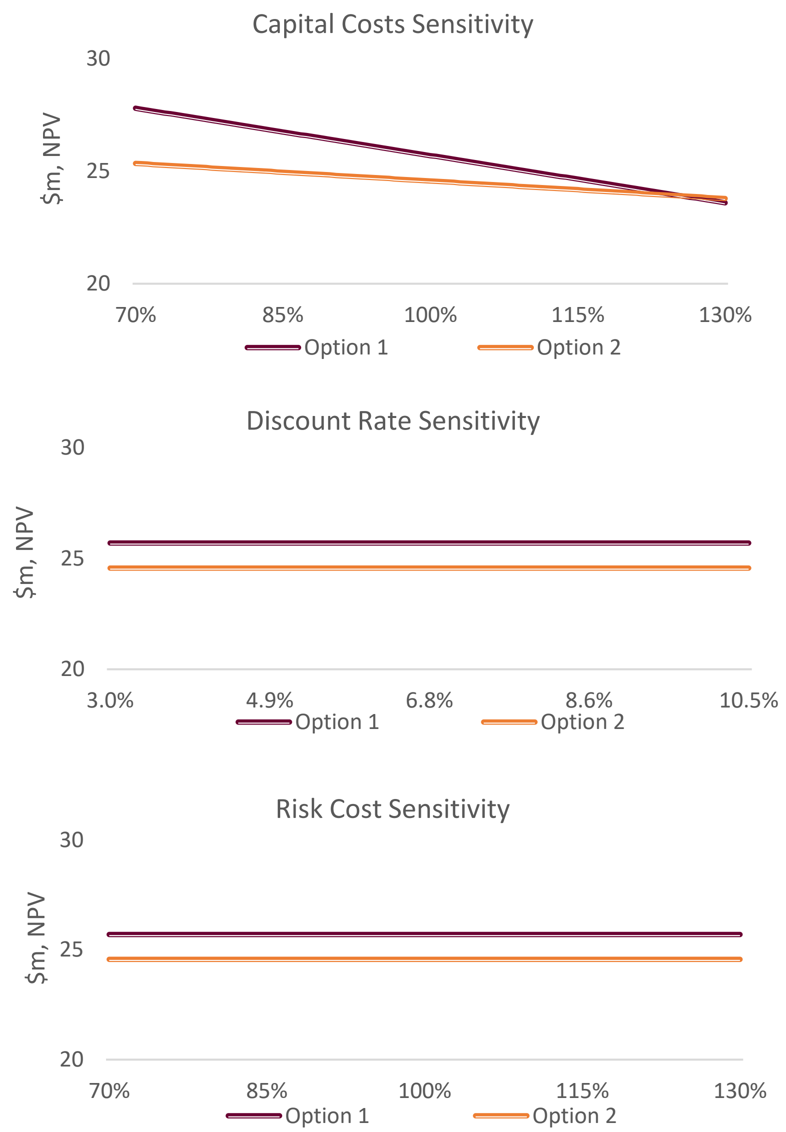
7.4.1. Sensitivity of the overall net market benefit

We have also reviewed the consequences for the preferred option of 'getting it wrong' if the key underlying input assumptions are not accurate.

The charts in Figure 6 below illustrate the estimated net market benefits for each option if the three 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 and Option 2 is found to be strongly positive across all three key assumptions.

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 input assumptions.

Figure 6 - 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 the 106 protection relays by 2028. This option is described in section 3 and is estimated to have a capital cost of $16.3 million.

Option 1 is the preferred option in accordance with NER clause 5.16.2(c) 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 $46 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 5.16.2(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 each of 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 conclude 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 conclude 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.[21]

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21 In accordance with NER clause 5.16.4(z2).

City West Substation

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 210.

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 Integrated System 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, alternative transmission options, interconnectors, generation, system strength services, 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 5.16.2(b)(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 $46 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 5.15A.2(b)(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 5.15A.2(b)(4) except those classes specified in clauses 5.15A.2(b)(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

This appendix defines the terms used in the economic assessment.

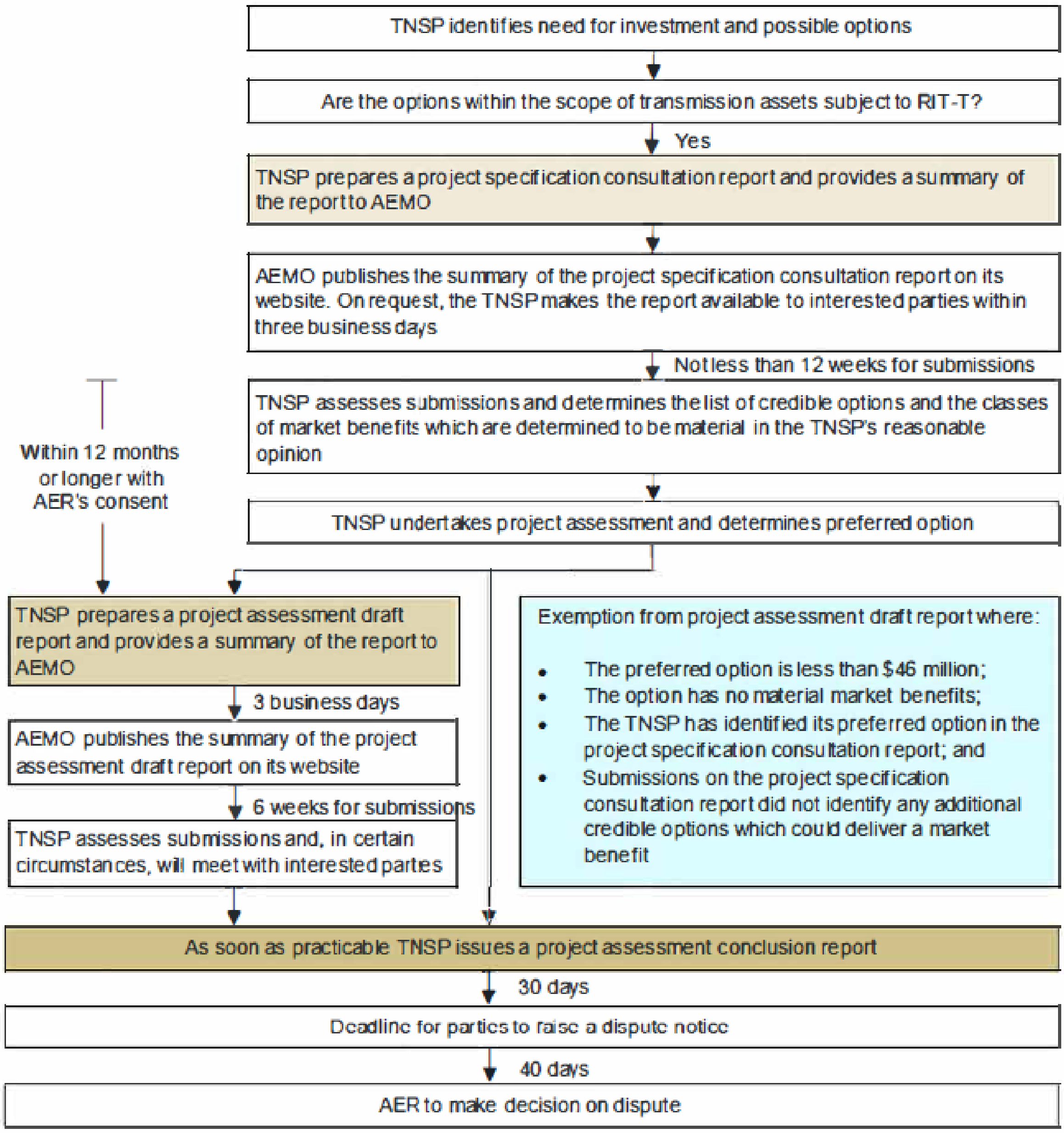
Definitions	
AEMO	Australian Energy Market Operator
Base case	A situation in which no option is implemented by, or on behalf of the transmission network service provider.
Commercially feasible	An option is commercially feasible if a reasonable and objective operator, acting rationally in accordance with 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: address the identified need; is (or are) commercially and technically feasible; and 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.

Definitions	
Market benefit	Market benefit must be: the present value of the benefits of a credible option calculated by: comparing, for each relevant reasonable scenario: the state of the world with the credible option in place to the state of the world in the base case, And weighting the benefits derived in sub-paragraph (i) by the probability of each relevant reasonable scenario occurring. 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.
Technically feasible	An option is technically feasible if there is a high likelihood that it will, if developed, provide the services that the RIT–T proponent has claimed it could provide for the purposes of the RIT–T assessment.

Appendix C Process for implementing the RIT-T

For the purposes of applying the RIT-T, the NER establishes a typically three stage process, i.e.: (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 7 - The RIT-T assessment and consultation process



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