Business Case
Backup Reach Program

Executive Summary

Protection systems ensure the safe and reliable functioning of the power network during power system abnormalities. The primary function of the protection system is to detect and disconnect faults (for example, a power line on the ground) from the power system. To comply with the National Electricity Rules (NER), backup protection schemes are required to improve fault clearance reliability. This document covers the backup protection requirements for Ergon Energy only.

There is a need for backup protection augmentation in Ergon Energy's network. This was identified through a current state assessment of Ergon Energy's distribution network, which evaluated the ability of the protection system to detect minimum fault levels. The assessment found 53,000 km had inadequate backup protection. Inadequate backup protection poses risks to Ergon Energy, of which the most severe include: .

- Failure to comply with clause S5.1.9 of the NER resulting in a breach and an improvement notice issued
- Failure of primary protection to clear a fault with no backup protection, resulting in a member of the public or an employee inadvertently contacting an energised source and a single fatality

Four network options were evaluated in this business case. A 'Do nothing' option was rejected, as it could not address the compliance issues outlined above. The network options evaluated were:

Option 1 - **Comprehensive backup protection**: This involves relay changes and installation of additional devices such as three-phaser reclosers, Single Wire Earth Return (SWER) reclosers, line fuses and protection relays at each location.

Option 2 - Negative phase sequence protection: As per Option 1, but assumes Single Wire Earth protection is provided by enabling negative sequence protection in the upstream three-phase recloser. As a result, relative to Option 1 it requires 154 fewer three-phase reclosers but 152 more relay setting changes.

Option 3 – Non-traditional and dependent: Requires more relay changes than either Option 1 or 2, but also installation of fewer three-phaser reclosers, SWER reclosers, line fuses and protection relays at each location. Relies on non-protection related improvements, impact of other work programs and amendment of existing protection schemes.

Option 4 – Deferred version of Option 3: As per the description for Option 3, but with some of the required installations and relay changes deferred to the next regulatory period (2025 – 2030).

Ergon Energy aims to minimise expenditure in order to stabilise or reduce customer prices, however understands that this must be balanced against critical network performance objectives. These include network risk mitigation (e.g. safety, bushfire), regulatory obligations (e.g. safety, performance), customer reliability and preparing the network for the ongoing adoption of new technology by customers (e.g. solar PV). In this business case both safety and regulatory compliance are strong drivers.

To this end Option 4, with a direct cost of $23.4M in the 2020-25 regulatory period, is preferred as it has the least negative NPV result (-$19.6M) of the four options. An additional $11.9M of spend will be required in the 2025-2030 period to complete the works under this option.

The direct cost of the program for each submission made to the AER is summarised in the table below. Note that all figures are expressed in 2018/19 dollars and apply only to costs incurred within the 2020-25 regulatory period for the preferred option.

Regulatory Proposal	Draft Determination Allowance	Revised Regulatory Proposal
$23.4M	$0M	$23.4M

Contents

1. Introduction

Protection systems ensure the safe and reliable functioning of the power network during power system abnormalities. The primary function of the protection system is to detect and disconnect faults (for example, a power line on the ground) from the power system.

Reliable operation of protection schemes is vital to eliminating risks such as electrocution, damage to equipment and maintaining system stability. Failure of a protection scheme to operate correctly results in unsafe conditions until manual intervention or back up arrangements are invoked.

The National Electricity Rules (NER) requires that sufficient primary protection systems and back-up protection systems are installed to ensure that a fault of any fault type anywhere on the distribution system is automatically disconnected. Furthermore, the back-up protection needs to be designed in a manner that does not allow the power system (other than the faulted element) to be damaged.

1.1 Purpose of document

This document recommends the optimal capital investment necessary for implementation and upgrade of backup protection schemes to ensure reliable operation of the protection system. This document aims to extend the work done in the previous regulatory period whereby primary protection was assessed and remedial works issued.

This is a preliminary business case document and has been developed for the purposes of seeking funding for the required investment in coordination with the Energy Queensland (EQL) Revised Regulatory Proposal to the Australian Energy Regulator (AER) for the 2020-25 regulatory control period. Prior to investment, further detail will be assessed in accordance with the established Energy Queensland investment governance processes. The costs presented are in $2018/19 direct dollars. This document addresses the need for backup protection in Ergon Energy (Ergon) only.

1.2 Scope of document

This document lays out the requirement for augmenting distribution feeder protection with backup protection schemes to improve the reliability with which electrical faults are cleared when they occur, complying with the NER requirements.

1.3 Identified Need

This program is required to ensure Ergon Energy meets its legislated compliance obligations as well as addressing safety risks associated with lack of back up protection schemes.

Ergon Energy aims to minimise expenditure in order to stabilise or reduce customer prices; however, understands that this must be balanced against critical network performance objectives. These include network risk mitigation (e.g. safety, bushfire), regulatory obligations (e.g. safety, performance), customer reliability, security, and preparing the network for the ongoing adoption of new technology by customers (e.g. solar PV). In this business case both safety and regulatory compliance are strong drivers, based on the inadequate backup protection identified on a large portion of the network.

A current state assessment of the network has recently been undertaken by Ergon Energy based on the ability of the protection system to detect minimum fault levels on the distribution network. This assessment resulted in 53,000 km of network found to have inadequate backup protection.

The main benefits to establishing backup protection are:

- Compliance with NER requirements for power system protection, ensuring that faulted equipment does not cause consequential damage to adjacent network.

- Increased safety by ensuring faults are cleared from the distribution network.
- Provide reliability benefits by creating more protected sections (where line assets are installed) that can be independently isolated during system faults.
- The ability to perform maintenance on primary protection devices and maintain adequate protection for energised networks.
- Ensures that publicly accessible assets do not present hazardous voltages for power system earth faults.

1.4 Energy Queensland Strategic Alignment

Table 1 below details how the backup reach program contributes to Energy Queensland's corporate and asset management objectives. The linkages between these Asset Management Objectives and EQL's Corporate Objectives are shown in Appendix E.

Table 1: Asset Function and Strategic Alignment

Objectives	Relationship of Initiative to Objectives
Ensure network safety for staff contractors and the community	Ensure protection clearing times are sufficiently fast to reduce the energy released under fault conditions, reducing the likelihood of; catastrophic failure of equipment, ignition of a fire, and collateral damage including airborne debris. Ensure that faults are cleared that occur when the primary protection either fails to clear the fault or has failed in service.
Meet customer and stakeholder expectations	Reliably remove unsafe operating scenarios from the network, protecting customer and stakeholder equipment.
Manage risk, performance standards and asset investments to deliver balanced commercial outcomes	Reliable protection operation significantly reduces the safety risk of an uncleared fault to the public and to Ergon's equipment. Backup protection can reduce planned outages by allowing Ergon to perform maintenance on primary protection while keeping the network energised.
Develop Asset Management capability & align practices to the global standard (ISO55000)	Timely development of infrastructure, including appropriate protection schemes and using suitable asset standards aligns with the practices in ISO55000.
Modernise the network and facilitate access to innovative energy technologies	Providing comprehensive backup protection to the distribution network modernises Ergon's protection schemes, bringing them into line with industry practice and the NER requirements.

1.5 Applicable service levels

Corporate performance outcomes for this asset are rolled up into Asset Safety & Performance group objectives, principally the following Key Result Areas (KRA):

- Customer Index, relating to Customer satisfaction with respect to delivery of expected services
- Optimise investments to deliver affordable & sustainable asset solutions for our customers and communities

Corporate Policies relating to establishing the desired level of service are detailed in Appendix D.

Under the Distribution Authorities, EQL is expected to operate with an 'economic' customer value-based approach to reliability, with "Safety Net measures" for extreme circumstances. Safety Net measures are intended to mitigate against the risk of low probability vs high consequence network outages. Safety Net targets are described in terms of the number of times a benchmark volume of energy is undelivered for more than a specific time period. EQL is expected to employ all reasonable measures to ensure it does not exceed minimum service standards (MSS) for reliability, assessed by feeder types as

- System Average Interruption Duration Index (SAIDI), and;
- System Average Interruption Frequency Index (SAIFI).

Both the Safety Net and MSS performance information are publicly reported annually in the Distribution Annual Planning Reports (DAPR). MSS performance is monitored and reported within EQL daily.

1.6 Compliance obligations

Table 2 shows the relevant compliance obligations for this proposal.

Table 2: Compliance obligations related to this proposal

Legislation, Regulation, Code or Licence Condition	Obligations	Relevance to this investment
QLD Electrical Safety Act 2002 **QLD Electrical Safety Regulation 2006**	We have a duty of care, ensuring so far as is reasonably practicable, the health and safety of our staff and other parties as follows: • Pursuant to the Electrical Safety Act 2002, as a person in control of a business or undertaking (PCBU), EQL has an obligation to ensure that its works are electrically safe and are operated in a way that is electrically safe.[1] This duty also extends to ensuring the electrical safety of all persons and property likely to be affected by the electrical work.[2] • EQL has an obligation to provide adequate protection of its power system assets as per the QLD Electrical Safety Act 2002 s29, maintain transmission, sub transmission and distribution voltages within statutory limits, and provide the customer with an acceptable quality and reliability of supply including voltage levels as per QLD Electrical safety Regulation 2006 s11 • In accordance with the QLD Electrical Safety Regulation an earthing and protection system must provide reliable operation as well as maintaining safe step, touch and transfer potentials for all electrical equipment.	Implementation or upgrade of distribution protection schemes helps reliably detect and clear faults, meeting EQL's obligation to ensure works are electrically safe and helps ensure the electrical safety of EQL staff and the public.
Distribution Authority for Ergon Energy issued under section 195 of *Electricity Act 1994* (Queensland)	Under its Distribution Authority: • The distribution entity must plan and develop its supply network in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services." • The distribution entity will ensure, to the extent reasonably practicable, that it	Existing protection schemes protecting the 53000km with inadequate backup protection increase the risk of unnecessary protection trips, uncleared faults or slow clearing faults. This impacts the quality and reliability of electricity and can increase the number of outages and extend their duration due to

[1] Section 29, *Electrical Safety Act 2002*
[2] Section 30 *Electrical Safety Act 2002*

Legislation, Regulation, Code or Licence Condition	Obligations	Relevance to this investment
	achieves its safety net targets as specified." • The distribution entity must use all reasonable endeavours to ensure that it does not exceed in a financial year the Minimum Service Standards (MSS)	equipment damage or safety concerns. Improved protection schemes will help reduce the impact of the above to reasonable levels to prevent exceedance of the MSS.
National Electricity Rules, Chapter 5	Schedule S5.1 of the National Electricity Rules, Chapter 5 provides a range of obligations on Network Services Providers relating to Network Performance Requirements. These include: • Section S5.1.9 Protection systems and fault clearance times • Section S5.1a.8 Fault Clearance Times • Section S5.1.2 Credible Contingency Events	Subject to clauses S5.1.9(k) and S5.1.9(l), a Network Service Provider must provide sufficient primary protection systems and **back-up protection** systems (including breaker fail protection systems) to ensure that **a fault of any fault type anywhere** on its transmission system or distribution system is automatically disconnected in accordance with clause S5.1.9(e) or clause S5.1.9(f). S5.1.9(f) does not remove the obligation for backup protection, it provides the performance requirements for the backup protection. This ensures that the employed backup protection is configured in a manner that does not result in network damage. The network sections identified as part of the surveys would not be automatically isolated if primary protection fails to clear the fault. Reliable backup protection addresses this limitation.

1.7 Limitation of existing assets

Ergon has a network protection standard that requires a reach factor of 1.3 for numerical relays and 1.5 for electromechanical backup protection, which falls within the accepted industry best practice range. These reach factors ensure that any given fault is detected and automatically cleared, as required by clause S5.1.9 of the NER, taking into consideration accuracy of relays and primary plant. Power system studies by Ergon have found that 53,000km of the total 117,000km of Ergon's network have inadequate backup protection.

An example where the primary protection failed to operate, and backup protection was required to clear the fault but was unable to, was the Lakes Creek Zone Substation (March 2017). In this case an auxiliary system failure disabled the primary protection, the network had no backup protection. A power system fault occurred and 1000m of overhead line was annealed and required replacement.

Ergon Energy has a fleet of protection devices that are subject to a planned maintenance regime as well as having varying levels of monitoring capability. These monitoring and maintenance activities improve protection system availability, but do not ensure that the system is always able to automatically isolate faulted network sections for the areas that were identified in a power system study undertaken by EQL – refer to section 3.2.1. The inability to disconnect these sections can result in network damage as presented at Lakes Creek, or in the case of earth faults sustained hazardous voltages that does not meet the expectations of the Queensland Electricity Safety Regulation.

From 2014 to 2018 31 primary protection devices failed in service in the Capricorn region of the Ergon Energy network. This represents approximately 25% of Ergon Energy's relay population, so extrapolating that figure, in the four years from 2014-2018 it is reasonable to assume that approximately 120 relays failed in service in Ergon Energy's network.

This can be extrapolated to 300 relays over the whole Ergon network in a 10-year period. The list of locations of the failed devices is provided in Appendix G.

2 Counterfactual Analysis

2.1 Purpose of asset

Ergon's protection assets are vital to ensure the safe, reliable operation of the electricity grid in Queensland. Comprehensive primary and backup schemes are required to ensure network faults are cleared in a way that minimises the duration of a fault whilst also minimising the amount of network isolated to clear the fault. Protection schemes need to be robust enough so that faults that occur on the network are cleared automatically, without needing manual intervention, and that the schemes do not trip when there is no fault present.

2.2 Business-as-usual service costs

If no action is taken Ergon will not comply with the automatic disconnection requirements of the NER due to parts of the network not having protection schemes in place that can clear faults in the event of a single failed component.

For the identified network sections a concurrent protection relay failure and power system fault Ergon's network plant will remain uncleared, in some cases power system damage may result.

Additionally, an uncleared fault poses a safety risk to the public and to Ergon Energy's staff. Uncleared faults that cause damage leading to extended outages or to fatalities may lead to sizeable fines and reputational damage to Ergon Energy.

2.2.1 Key assumptions

The identification of site-specific requirements has been based on power system studies. The key assumptions that were used for this study are:

- No configurable gas switch installed as part of the reliability program can be converted to a protection enabled recloser to correct any of the identified risks.
- Some existing line fuses have an impact on the backup protection.
- Three phase reclosers that back up a Single Wire Earth Return (SWER) recloser are capable of Negative Phase Sequence
- No augmentation to the network or protection system in the past 12 months that address backup issues in the identified substations
- Where required to install a relay the substation has the required primary plant (for example, a spare Current Transformer (CT)) to support it.
- A backup reach ratio of 1.3 for numerical and 1.5 for electromechanical relays as per the Ergon protection standard can be successfully applied to reliably detect and clear faults.

2.3 Risk assessment

The risks in Table 3 have been identified as a result of not addressing the identified limitations. This risk assessment is in accordance with the EQL Network Risk Framework and the Risk Tolerability table from the framework is shown in Appendix F

Table 3: Counterfactual risk assessment

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Primary protection fails to detect a fault or to operate which results in a member of the public inadvertently contacting an energised source and **a single fatality**.	Safety	5 *(Single fatality)*	3 *(Unlikely)*	**15** ***(Moderate)***	2019
Failure of an 11kV feeder protection relay to operate following a high voltage (HV) fault initiated through HV live work, resulting in **a single fatality** to an employee or member of the public.	Safety	5 *(Single fatality)*	2 *(Very unlikely)*	**10** ***(Low)***	2019
Failure of a protection service at a Commercial and Industrial (C&I) substation and subsequent network fault causes a fire resulting in **a single fatality**.	Safety	5 *(Single fatality)*	2 *(Very unlikely)*	**10** ***(Low)***	2019
Failure to provide backup protection results in a breach of National Electricity Rules and an **improvement notice issued by the regulator**.	Legislated	4 *(Energex/Ergon identified issue requiring regulator to be notified. Improvement notice issued)*	3 *(Unlikely)*	**12** ***(Moderate)***	2019
Primary protection fails to detect a fault or operate, with no or slow clearing backup protection which results in **annealing of conductor requiring replacement and Significant impact on any restoration or planned works equating to business impact of >$500,000**.	Business	3 *(Significant impact on any restoration or planned works equating to business impact of >$500,000)*	3 *(Unlikely)*	**9** ***(Low)***	2019

2.4 Retirement or de-rating decision

Protection systems are designed to allow the anticipated load current while maintaining the maximum sensitivity for network faults. Protection systems designed with this performance expectation have no further adjustment that can be made without impacting on service to customers.

3 Options Analysis

3.1 Options considered but rejected

The following options to reduce the need for backup protection were considered but rejected due to safety on the basis of cost, complexity or customer impacts.

- Restrict load or load growth or implement load encroachment logic to allow the protection pickup to be set closer to load current.

The following option is rejected as a whole-of-network solution due to customer impacts but may be an available option at some sites dependent on site-specific analyses:

- Where two zone substation transformers are operating in parallel, split the Low Voltage busses to allow transformer LV overcurrent protection to see more fault current, effectively increasing protection reach (up to double) without adjusting settings.

3.2 Identified options

The following four network options have been identified and assessed in this analysis:

- Option 1 – Comprehensive backup protection;
- Option 2 – Negative phase sequence protection;
- Option 3 – Non-Traditional and dependent option; and,
- Option 4 – Option 3 delivered over two regulatory periods.

3.2.1 Network options

All the identified options except for the ‘Do Nothing’ approach may include the following depending on site-specific equipment and network configuration:

- Network reconfigurations so that existing protection can provide the appropriate backup reach
- Circuitry changes to modify existing device functionality

The backup reach design for each zone substation is expected to have a mix of setting changes, reclosers, fuses, or protection relays. Where it is possible to expedite elements of the design due to the simplicity of execution, they will be brought forward to minimise the compliance exposure.

Option 1 – Comprehensive backup protection

This option involves the installation of additional devices such as reclosers, fuses and protection relays at the location that can directly address the backup protection issue. The use of protection elements such as negative phase sequence (NPS) overcurrent protection has been avoided for multiphase systems as it would not necessarily address fault balanced fault conditions.

Following analysis of the outcomes of the desktop power systems study of the network, a range of criteria were identified to assist in estimation of works required for rectifying the backup protection issues on the network. The criteria and assumptions made are in Appendix H.

To provide backup coverage using the outcomes of this analysis the following is scope is proposed:

- 398 relay setting changes.
- 1143 new three-phase line reclosers.
- 322 new SWER reclosers.
- 707 new line fuses.
- 243 new protection relays.

Option 2 – Negative phase sequence protection

This option assumes that all network backup protection that is required to be provided by a three-phase device is completed, but that backup protection for SWER is provided by enabling negative sequence protection in the upstream three-phase recloser. The risks associated with this option are:

- Lack of data for standing Negative Phase Sequence currents;
- Need to change operational requirements during switching and paralleling network; and,
- Further developing tools to enable designs efficient design times for determining the setting values.

The assessment criteria scope changes from Option 1 is available in Appendix I.

To provide backup coverage using the outcomes of this analysis the following is required:

- 552 relay setting changes.
- 989 new three-phase line reclosers.
- 322 new SWER reclosers.
- 707 new line fuses.
- 243 new protection relays.

Option 3 – Non-Traditional and dependent option

Option 3 has been developed with several additional assumptions in comparison to Option 1. These assumptions include but are not limited to non-protection related improvements, possible amendments to available protection schemes to provide protection and the impact of other program of works. This option relies on the following additional assumptions:

- Improved network information prior to works being completed i.e. Unknown line fuse sizes are collected.
- Setting changes will also occur within the same regulatory period.
- Required protection setting changes on aged relays will be undertaken in conjunction with or by the Repex program for replacing end-of-life and obsolete relays.
- Where CAPEX augmentation projects are undertaken in an area with inadequate backup protection, network configuration will be adjusted, and some additional protection works will be added to provide adequate backup protection.
- Where possible, existing configurable load break switches on the network will be converted to protection devices.
- Utilisation of Sensitive Earth Fault (SEF) to provide Earth Fault (EF) protection support.
- Utilisation of Negative Phase Sequence to provide phase and EF protection support.
- A setting change on one device will improve protection for several backup zones.

The remaining criteria differences to Option 1 are available in Appendix J.

To provide backup coverage using the outcomes of this analysis the following is required:

- 711 relay setting changes.
- 353 new three-phase line reclosers.
- 237 new SWER reclosers.
- 140 new line fuses.
- 35 new protection relays.

Option 4 – Option 3 delivered over two regulatory periods

This option has been proposed to reduce the proposed expenditure in the next regulatory period. This option extends the exposure of the risk on the network. The following assumptions have been made:

- The same network assumptions as used in option 3.
- The remaining installations will occur in the 2025-2030 regulatory period.

To provide backup coverage under this option the following is required to be installed in the 2020-25 regulatory period:

- 389 relay setting changes.
- 230 new three-phase line reclosers.
- 200 new SWER reclosers.
- 35 new line fuses.
- 13 new protection relays.

The remaining, shown below, will be installed in the 2025-30 regulatory period:

- 322 relay setting changes.
- 123 new three-phase line reclosers.
- 37 new SWER reclosers.
- 105 new line fuses.
- 22 new protection relays.

3.2.2 Non-network options

There are no non-network options identified to address the risks caused by no or inadequate backup protection on distribution feeders.

3.3 Economic analysis of identified options

3.3.1 Cost versus benefit assessment of each option

Capital Costs (CAPEX)

The capital costs (CAPEX) for each option have been determined based on the volumes of capital works defined in Section 3.2.1, and the following unit costs, derived from past projects and standard estimates:

- Setting Change - $1,444.
- Install a SWER Recloser - $42,872.
- Install a Three Phase Recloser - $55,781.
- Install a Line Fuse - $10,209.
- Install a Relay - $86,000.

The direct cost for each option over the next regulatory period is shown in Table 4. The cost summary is shown in $18/19 direct dollars.

Table 4: 2020-25 Cost Summary

Direct Cost	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Option 1	$21.2M	$21.2M	$21.2M	$21.2M	$21.2M	$106.0M
Option 2	$19.6M	$19.6M	$19.6M	$19.6M	$19.6M	$98.0M
Option 3	$7.1M	$7.1M	$7.1M	$7.1M	$7.1M	$35.5M
Option 4	$4.7M	$4.7M	$4.7M	$4.7M	$4.7M	$23.5M

Option 4 includes an additional $11.9M required during the 2025-2030 regulatory period.

Results

A 20-year Net Present Value (NPV) analysis of the identified options was also carried out as part of this analysis, outlining the Present Value (PV) of costs discounted over a 20-year study period from 2019 to 2039 at the Regulated Real Pre-Tax Weighted Average Cost of Capital (WACC) rate of 2.62%. All capital costs outlined in Table 4 were included, along with the deferred $11.9M associated with Option 4, spread evenly over the 2025-2030 regulatory period.

Table 5 contains the results of this analysis, confirming that Option 4 is the most cost-effective option even when accounting for residual value of assets and discounting effects.

Table 5: Net Present Value of Options

Option	Net Present Value ($M)	PV of costs ($M)
Option 1: Comprehensive backup protection	-$88.88	-$88.88
Option 2: Negative sequence protection	-$81.88	-$81.88
Option 3: Non-traditional and dependant option	-$29.54	-$29.54
Option 4: Option 3 delivered over two regulatory periods	-$19.61	-$19.61

3.4 Scenario Analysis

3.4.1 Sensitivities

A high-level sensitivity analysis was carried out on the unit rates used to compose cost estimates in this business case. Sensitivities of +/-20% were considered on all unit rates, with the NPV results of each option under different sensitivities shown in Table 6.

Table 6: Results of sensitivity analysis

Sensitivity Results (NPV $M)	CAPEX Unit Rate Sensitivity		
	0%	20%	-20%
Option 1: Comprehensive backup protection	$88.9	$106.7	$71.1
Option 2: Negative sequence protection	$81.9	$98.3	$65.5
Option 3: Non-traditional and dependant option	$29.5	$35.5	$23.6
Option 4: Option 3 delivered over two regulatory periods	$26.4	$31.7	$21.2

Option 4 was the least-cost option under each sensitivity tested. The following key points were noted with regards to each cost estimate and capital cost sensitivity:

- Option 3 is based on Option 2, with several additional assumptions involving bundling with other network programs. There is a reliance on other programs installing additional three-phase reclosers that can be used for backup protection rectification, and that existing load-break switches can be converted to protection reclosers. Due to the increased risk of these assumptions, the cost sensitivity has been varied upwards by 20% to account for a possible 10% increase in costs from the estimates used and additional 10% if new reclosers are required where the identified existing switches cannot be economically converted to protection reclosers.

Additionally, backup reach is sensitive to the length of the feeder being protected. As the network grows, the minimum fault level on a feeder can be reduced. Over time this can increase the number of locations that do not have sufficient backup protection. If there is expansive, non-forecast growth in the network additional sites not identified may require augmentation. Alternatively, network reconfiguration where necessary to move load from overloaded feeders to lightly loaded feeders may introduce a new minimum fault level that requires backup protection augmentation.

3.4.2 Value of regret analysis

In terms of selecting a decision pathway of ‘least regret’, Option 4 presents an economically efficient, balanced approach to investment by targeting backup protection works based on cost and reliability assessments and reducing risk to an extent. There remains an extended period of risk under Option 4 that would be significantly reduced under Option 3 at the expense of cost.

The key potential regrets in this case are:

- Uncleared or slow clearing fault on the distribution network causing electrocution of an employee or member of the public, leading to a fatality due to primary protection failing to clear the fault and inadequate backup protection in place.
- A safety incident resulting from a failed protection relay prompts an external investigation finding Ergon Energy in breach of the NER section 5.1.9.
- Backup protection installed only covers Phase-Ground or Phase-Phase faults. A three-phase fault occurs, and primary protection fails to clear the fault. Significant annealing of conductor occurs due to extended fault duration, resulting in large repair expenditure.

Load growth in the network, or lack of it, can impact viable protection options. Overcurrent protection must be set safely above load current, and in some cases the required minimum fault to be backed up can be significantly below load. Conversely, reducing load can enable a protection device to provide backup to a network it previously could not, lowering the need for additional devices. Load forecasts will be taken into account during the project approval process.

The proposed option will reduce or eliminate the identified key risks.

3.5 Qualitative comparison of identified options

3.5.1 Advantages and disadvantages of each option

Table 7 details the advantages and disadvantages of each option considered.

Table 7: Qualitative Assessment of Options

Options	Advantages	Disadvantages
Option 1 – Traditional Solution	• Significantly reduces risk of uncleared faults • Brings whole of network into compliance with the NER and QLD electrical safety regulations • Improves safety of the public across Ergon's network • New protection devices allow for better sectionalisation of the network, increasing network reliability • New protection devices make locating a fault more effective, reducing the return to service period.	• Higher on-going maintenance costs due to increased number of protection relays and reclosers
Option 2 – Negative Sequence	• Significantly reduces risk of uncleared faults • Brings whole of network into compliance with the NER and QLD electrical safety regulations • Improves safety of the public across Ergon's network • New protection devices allow for better sectionalisation of the network, increasing network reliability • New protection devices make locating a fault more effective, reducing the return to service period.	• High capital cost • Requires changes to Protection and Earthing Policy • Effectiveness of NPS protection not tested within Ergon's network
Option 3 – Non-Traditional Solution	• Reduces risk of uncleared faults • Brings most of network into compliance with the NER and QLD electrical safety regulations • Improves safety of the public across Ergon's network • New protection devices allow for better sectionalisation of the network, increasing network reliability • New protection devices make locating a fault more effective, reducing the return to service period. • Lower capital cost	• Effectiveness of NPS protection not tested within Ergon's network • Using SEF to provide EF protection support will result in slow clearing earth faults, increasing risk • Relies on assumptions that other augmentation and REPEX projects will provide devices to the network that will assist in resolving backup inadequacy • Assumes that the minimum faults on multiphase networks are phase-phase, not three-phase. Three-phase faults are not able to be cleared by NPS.

Options	Advantages	Disadvantages
Option 4 – Non-Traditional Solution over two regulatory periods	• Reduces risk of uncleared faults • Brings most of network into compliance with the NER and QLD electrical safety regulations • Improves safety of the public across Ergon's network • New protection devices allow for better sectionalisation of the network, increasing network reliability • New protection devices make locating a fault more effective, reducing the return to service period. • Spreads cost over two regulatory periods	• Effectiveness of NPS protection not tested within Ergon's network • Using SEF to provide EF protection support will result in slow clearing earth faults, increasing risk • Relies on assumption that other augmentation and REPEX projects will provide devices to the network that will assist in resolving backup inadequacy • Assumes that the minimum faults on multiphase networks are phase-phase, not three-phase. Three-phase faults are not able to be cleared by NPS. • Extended period of time where parts of Ergon's network are not compliant and have increased risk

3.5.2 Alignment with network development plan

One of the core focusses of Ergon's DAPR is to provide high levels of safety and reliability. Full coverage of primary and backup protection on the distribution network is necessary to safely and reliably de-energise faults, which pose a high safety risk to the public and Ergon Energy employees.

Where possible, it has been planned to coordinate the works under this project with other refurbishment works including replacement of end-of-life relays and circuit breakers, as well as transformer upgrades. This will occur as part of Ergon Energy's business as usual replacement planning functions.

3.5.3 Alignment with future technology strategy

This program of work provides additional monitoring points that can provide network information to support Energy Queensland's transition to an Intelligent Grid, in line with the Future Grid Roadmap and Intelligent Grid Technology Plan. It also supports Energy Queensland in maintaining affordability of the distribution network while also maintaining safety, security and reliability of the energy system, a key goal of the Roadmap. The proposed works accommodate new assets which are designed to modern standards, increasing the reliability and safety of the asset group.

3.5.4 Risk Assessment Following Implementation of Proposed Option

Table 8: Risk assessment showing risks mitigated following Implementation

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Protection fails to detect a fault or to operate which results in a member of the public inadvertently contacting an energised source and **a single fatality**.	Safety	*(Original)* *5* *(Single fatality)*	*3* *(1 in 1,000)*	***15*** ***(Moderate)***	2019
		(Mitigated) 5 *(As above)*	1 *(Almost no likelihood)*	**5** ***(Very Low)***	

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Failure of an 11kV feeder protection relay to operate following a High Voltage (HV) fault initiated through HV live work, resulting in **a single fatality** to an employee or member of the public.	Safety	*(Original)* *5* *(Single fatality)* (Mitigated) 5 *(As Above)*	 *2* *(Very unlikely)* 1 *(Almost no likelihood)*	 ***10*** ***(Low)*** **5** ***(Very Low)***	2019
Failure of a protection service at a C&I substation and subsequent network fault causes a fire resulting in **a single fatality**.	Safety	*(Original)* *5* *(Single fatality)* (Mitigated) 5 *(As Above)*	 *2* *(1 in 10,000)* 1 *(Almost no likelihood)*	 ***10*** ***(Low)*** **5** ***(Very Low)***	2019
Failure to provide backup protection results in a breach of National Electricity Rules and an **improvement notice issued by the regulator**.	Legislated	*(Original)* *4* *(Energex/Ergon identified issue requiring regulator to be notified. Improvement notice issued)* (Mitigated) 4 *(As Above)*	 *3* *(Unlikely)* 1 *(Almost no likelihood)*	 ***12*** ***(Moderate)*** **4** ***(Very Low)***	2019
Primary protection fails to detect a fault or operate, with no or slow clearing backup protection which results in **annealing of conductor requiring replacement and Significant impact on any restoration or planned works equating to business impact of >$500,000**.	Business	*(Original)* *3* *(Significant impact on any restoration or planned works equating to business impact of >$500,000)* (Mitigated) 3 *(As Above)*	 *3* *(1 per year)* 1 *(Almost no likelihood)*	 ***9*** ***(Low)*** **3** ***(Very Low)***	2019

4 Recommendation

4.1 Preferred option

The preferred option is Option 4, the non-traditional and dependant option which rectifies a portion of the backup protection inadequacies for a cost of $23.4M over the 2020-25 regulatory period with the remaining works to be addressed in the 2025-30 regulatory period.

4.2 Scope of preferred option

To provide backup coverage under this option the following is required to be installed in the 2020-25 regulatory period:

- 389 relay setting changes.
- 230 new three-phase line reclosers.
- 200 new SWER reclosers.
- 35 new line fuses.
- 13 new protection relays.

The remaining, shown below, will be installed in the 2025-30 regulatory period:

- 322 relay setting changes.
- 123 new three-phase line reclosers.
- 37 new SWER reclosers.
- 105 new line fuses.
- 22 new protection relays.

Appendix A. References

Note: Documents which were included in Energy Queensland's original regulatory submission to the AER in January 2019 have their submission reference number shown in square brackets, e.g. Energy Queensland, *Corporate Strategy [1.001], (31 January 2019).*

Energy Queensland, *Asset Management Overview, Risk and Optimisation Strategy [7.025]*, (31 January 2019).

Energy Queensland, *Corporate Strategy [1.001],* (31 January 2019).

Energy Queensland, *Future Grid Roadmap [7.054],* (31 January 2019).

Energy Queensland, *Intelligent Grid Technology Plan [7.056],* (31 January 2019).

Energy Queensland, *Network Risk Framework*, (October 2018).

Ergon Energy, *Distribution Annual Planning Report (2018-19 to 2022-23) [7.049]*, (21 December 2018).

Appendix B. Acronyms and Abbreviations

The following abbreviations and acronyms appear in this business case.

Abbreviation or acronym	Definition
$M	Millions of dollars
$ nominal	These are nominal dollars of the day
$ real 2019-20	These are dollar terms as at 30 June 2020
2020-25 regulatory control period	The regulatory control period commencing 1 July 2020 and ending 30 Jun 2025
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMP	Asset Management Plan
Augex	Augmentation Capital Expenditure
BAU	Business As Usual
CAPEX	Capital expenditure
CB	Circuit Breaker
C&I	Commercial and Industrial (substation)
CT	Current Transformer
Current regulatory control period or current period	Regulatory control period 1 July 2015 to 30 June 2020
DAPR	Distribution Annual Planning Report
DAP	Direct approved cost
DC	Direct Current
DNSP	Distribution Network Service Provider
EF	Earth Fault
EQL	Energy Queensland Ltd
HV	High Voltage
IT	Information Technology
KRA	Key Result Areas
kV	Kilovolt
LV	Low Voltage
MSS	Minimum Service Standard
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules (or Rules)

Abbreviation or acronym	Definition
Next regulatory control period or forecast period	The regulatory control period commencing 1 July 2020 and ending 30 Jun 2025
NPS	Negative Phase Sequence
NPV	Net Present Value
OC	Overcurrent
OPEX	Operational Expenditure
PCBU	Person in Control of a Business or Undertaking
Previous regulatory control period or previous period	Regulatory control period 1 July 2010 to 30 June 2015
PV	Present Value
Repex	Replacement Capital Expenditure
RIN	Regulatory Information Notice
RIT-D	Regulatory Investment Test – Distribution
RTS	Return to Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAMP	Strategic Asset Management Plan
SCADA	Supervisory Control and Data Acquisition
SEF	Sensitive Earth Fault
SWER	Single Wire Earth Return
WACC	Weighted average cost of capital
ZS	Zone Substation

Appendix C. Alignment with the National Electricity Rules (NER)

The table below details the alignment of this proposal with the NER capital expenditure requirements as set out in Clause 6.5.7 of the NER.

Table 9: Alignment with NER

Capital Expenditure Requirements	Rationale
6.5.7 (a) (2) The forecast capital expenditure is required in order to **comply with all applicable regulatory obligations or requirements** associated with the provision of standard control services	Refer to Table 2 in section 1.4 of this report for the relevant regulatory and compliance obligations.
6.5.7 (a) (3) The forecast capital expenditure is required in order to: (iii) maintain the **quality, reliability and security of supply** of supply of standard control services (iv) maintain the **reliability and security of the distribution system** through the supply of standard control services	Robust protection schemes are a key component in ensuring that EQL does not exceed minimum service standards for reliability, including; • System Average Interruption Duration Index (SAIDI) • System Average Interruption Frequency Index (SAIFI) By ensuring that the number of customers de-energised to isolate a fault is minimised, and that the duration of the de-energisation is minimised by ensuring a fault is cleared as quickly as possible to reduce damage caused by fault energy to the distribution system.
6.5.7 (a) (4) The forecast capital expenditure is required in order to maintain the **safety of the distribution system** through the supply of standard control services.	Protection schemes must operate quickly and reliably to isolate faulted sections of the network. Electricity faults, especially those involving a conductor on the ground, pose a significant safety risk to EQL staff and the public until they are de-energised. Protection devices are mechanical and digital and by nature these devices are at risk of failure. Due to this, it is necessary to ensure that any fault on the network can be detected and isolated by a minimum of two separate protection devices to maintain the safety of the distribution system.
6.5.7 (c) (1) (i) The forecast capital expenditure reasonably reflects the **efficient costs** of achieving the capital expenditure objectives	The Unit Cost Methodology and Estimation Approach sets out how the estimation system is used to develop project and program estimates based on specific material, labour and contract resources required to deliver a scope of work. The consistent use of the estimation system is essential in producing an efficient CAPEX forecast by enabling: • Option analysis to determine preferred solutions to network constraints • Strategic forecasting of material, labour and contract resources to ensure deliverability • Effective management of project costs throughout the program and project lifecycle, and • Effective performance monitoring to ensure the program of work is being delivered effectively. The unit costs that underpin our forecast have also been independently reviewed to ensure that they are efficient (Attachments 7.004 and 7.005).
6.5.7 (c) (1) (ii) The forecast capital expenditure reasonably reflects the costs that **a prudent operator** would require to achieve the capital expenditure objectives	The prudency of this proposal is demonstrated through the options analysis conducted and the quantification of risk and benefits of each option. The prudency of our CAPEX forecast is demonstrated through the application of our common frameworks put in place to effectively manage investment, risk, optimisation and governance of the Network Program of Work. An overview of these frameworks is set out in our Asset Management Overview, Risk and Optimisation Strategy (Attachment 7.026).

Appendix D. Mapping of Asset Management Objectives to Corporate Plan

This proposal has been developed in accordance with our Strategic Asset Management Plan. Our Strategic Asset Management Plan (SAMP) sets out how we apply the principles of Asset Management stated in our Asset Management Policy to achieve our Strategic Objectives.

Table 1: "Asset Function and Strategic Alignment" in Section 1 details how this proposal contributes to the Asset Management Objectives.

The Table below provides the linkage of the Asset Management Objectives to the Strategic Objectives as set out in our Corporate Plan (Supporting document 1.001 to our Regulatory Proposal as submitted in January 2019).

Table 10: Alignment of Corporate and Asset Management objectives

Asset Management Objectives	Mapping to Corporate Plan Strategic Objectives
Ensure network safety for staff contractors and the community	EFFICIENCY ***Operate safely as an efficient and effective organisation*** Continue to build a strong safety culture across the business and empower and develop our people while delivering safe, reliable and efficient operations.
Meet customer and stakeholder expectations	COMMUNITY AND CUSTOMERS ***Be Community and customer focused*** Maintain and deepen our communities' trust by delivering on our promises, keeping the lights on and delivering an exceptional customer experience every time
Manage risk, performance standards and asset investments to deliver balanced commercial outcomes	GROWTH ***Strengthen and grow from our core*** Leverage our portfolio business, strive for continuous improvement and work together to shape energy use and improve the utilisation of our assets.
Develop Asset Management capability & align practices to the global standard (ISO55000)	EFFICIENCY ***Operate safely as an efficient and effective organisation*** Continue to build a strong safety culture across the business and empower and develop our people while delivering safe, reliable and efficient operations.
Modernise the network and facilitate access to innovative energy technologies	INNOVATION ***Create value through innovation*** Be bold and creative, willing to try new ways of working and deliver new energy services that fulfil the unique needs of our communities and customers.

Appendix E. Risk Tolerability Table

The Energy Queensland Network Risk Framework assesses individual risks in dimensions of Likelihood and Consequence according to a six by six risk matrix.

Risk Analysis 6x6 multiplication R=C x L	Consequence → 1	2	3	4	5	6
Likelihood ↑ 6	6	12	18	24	30	36
5	5	10	15	20	25	30
4	4	8	12	16	20	24
3	3	6	9	12	15	18
2	2	4	6	8	10	12
1	1	2	3	4	5	6

Network Risks - ***Risk Tolerability Criteria and Action Requirements***

Risk Score	Risk Descriptor	Risk Tolerability Criteria and Action Requirements		
30 – 36	***Intolerable*** *(stop exposure immediately)*			
24 – 29	***Very High Risk***	***ALARP** Risk in this range managed to As Low As Reasonably Practicable	**Executive Approval** (required for continued risk exposure at this level)	May require a full Quantitative Risk Assessment (QRA) Introduce new or changed risk treatments to reduce level of risk Periodic review of the risk and effectiveness of the existing risk treatments
18 – 23	***High Risk***		**Divisional Manager Approval** (required for continued risk exposure at this level)	Introduce new or changed risk treatments to reduce level of risk Periodic review of the risk and effectiveness of the existing risk treatments
11 – 17	***Moderate Risk***		**Group Manager / Process Owner Approval** (required for continued risk exposure at this level)	Introduce new or changed risk controls or risk treatments as justified to further reduce risk Periodic review of the risk and effectiveness of the existing risk treatments
6 – 10	**Low Risk**			
1 to 5	***Very Low Risk***		No direct approval required but evidence of ongoing monitoring and management is required	*Periodic review of the risk and effectiveness of the existing risk treatments*

**Note: SOFAIRP to be used for Safety Risks and ALARP for Network Risks*

Figure 1: A Risk Tolerability Scale for evaluating Semi-Quantitative risk score

Appendix F. Reconciliation Table

Reconciliation Table Conversion from $18/19 to $2020	
Business Case Value	
(M$18/19)	$23.40
Business Case Value	
(M$2020)	$24.21

Appendix G. List of location of failed in service primary devices in Capricorn, 2014 to 2018

- Agnes Waters ZS 66/11kV transformer May 2014
- Awoonga ZS Boyne Residential 66kV feeder May 2016
- Clermont ZS Barcaldine 132kV feeder April 2016
- Berseker ZS Lakes Creek 66kV feeder August 2017
- Biloela ZS Thangool 22kV feeder November 2015
- Bingegang ZS 66/11kV transformer October 2017
- Calliope ZS 66kV bus September 2014
- Emerald ZS 11kV Anakie feeder line recloser July 2017
- Frenchville ZS 66kV bus September 2014
- Gladstone Friend Street ZS Gladstone South 66kV line February 2018
- Gladstone Friend Street ZS 66/11kV transformer November 2018
- Lakes Creek ZS 66kV bus July 2015
- Lakes Creek ZS 11kV line recloser September 2018
- Longreach ZS 19.1kV SWER recloser (Stonehenge) December 2014
- Longreach ZS 19.1kV SWER recloser (Strathfield) October 2017
- Longreach ZS 19.1kV SWER recloser (Silverwood) April 2018
- Longreach ZS 19.1kV SWER recloser (Morella) August 2018
- Longreach ZS 19.1kV SWER recloser (Gordonvale) November 2018
- Monto ZS 66kV Littlemore feeder April 2018
- Mount Morgan ZS 66kV Mine feeder September 2017
- Raglan ZS 66kV Egans Hill feeder March 2015
- Raglan ZS 22kV Neutral March 2015
- Rocky Glenmore ZS 11kV Wandal feeder December 2014
- Rolleston ZS 19.1kV SWER recloser (Wealwandangie) March 2017
- Rolleston ZS 19.1kV SWER recloser (X589832) May 2017
- Rolleston ZS 19.1kV SWER recloser (Barkala) June 2017
- Theodore ZS 19.1kV SWER recloser (X2783) August 2016
- Theodore ZS 19.1kV SWER recloser (CB595894) January 2017
- Wiggins Island ZS 33kV Earthing transformer diff April 2016
- Wowan ZS 12.7kV SWER (Goovigen) February 2017
- Wowan ZS 12.7kV SWER (Woorabinda) October 2017

Appendix H. Option 1 assumptions and criteria

The scope of work has used the following assumptions when developing solutions:

- **SWER Network – Relay is an existing backup device**
  - Fuses are not to be used on SWER Networks.
  - Total length for the device < 1km – Setting change to the upstream device.
  - Total length > 90% Total Protected Length – Install one (1) Three phase recloser.
  - Number of Groups = 1 – Install one (1) new SWER recloser.
  - Total length for the device <10km – Install one (1) new SWER recloser.
  - Total length > 10km & Total length < 50% of Total Protected Length – Install the same number of SWER reclosers as groups (Max of 3).
  - Total length > 10km & Total length > 50% of Total Protected Length – Manually determine the number of SWER reclosers to be installed.
  -

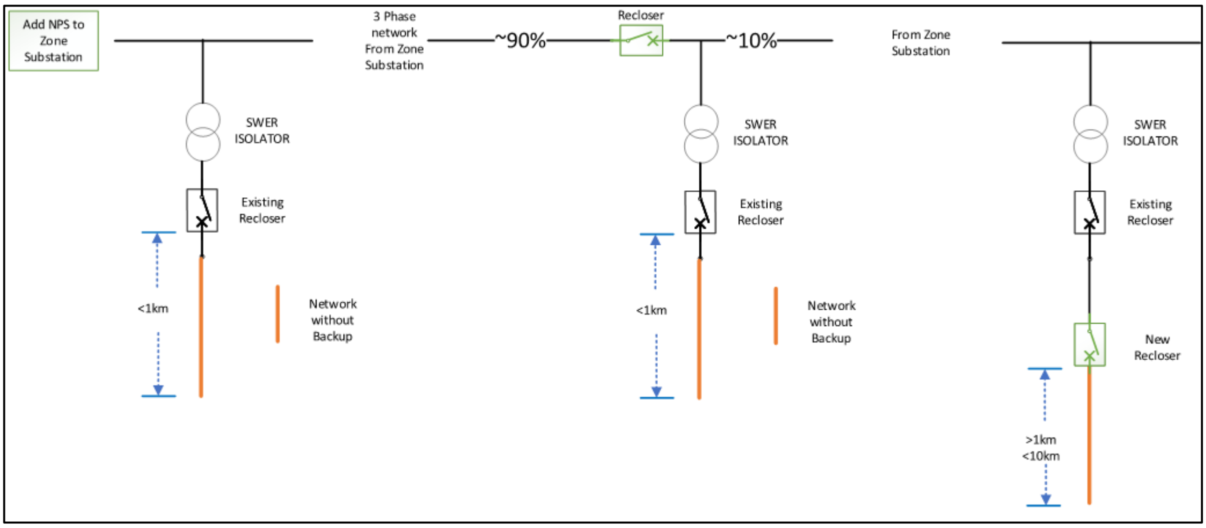

Figure 2-Proposed SWER Backup from substation relay

- **SWER Network – Three phase recloser is an existing backup device**
  - Fuses are not to be used on SWER Networks.
  - Total length for the device > 100km - Install one (1) new SWER recloser and configure Negative Phase Sequence in the existing three-phase device.
  - Total length for the device < 100km - Configure Negative Phase Sequence in the existing three-phase device.

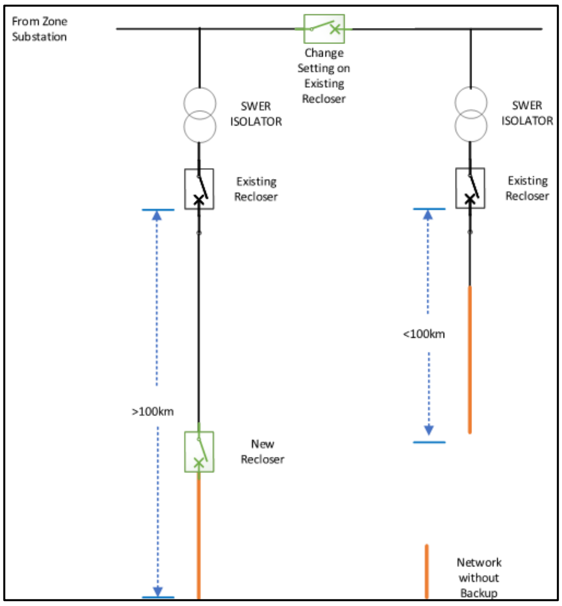

Figure 3 Proposed SWER Backup from existing line recloser

- **SWER Network – SWER recloser is an existing backup device**
  - Fuses are not to be used on SWER Networks.
  - Total length for the device < 1km – Setting change to the upstream device.
  - Number of Groups = 1 – Install one (1) new SWER recloser.
  - Total length < 50% of Total Protected Length – Install the same number of SWER reclosers as groups (Max of 3).
  - Total length > 50% of Total Protected Length – Manually determine the number of SWER reclosers to be installed (Max of 3).

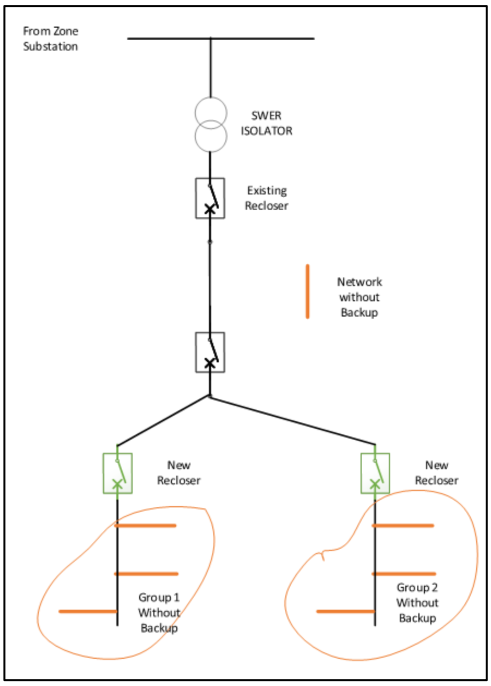

Figure 4 Proposed SWER backup for existing SWER recloser

- **Multiphase Network – Relay is the existing main device**
  - Total length of the device or Mean length < 1km & Number of Groups > 10 – Install one (1) new recloser.
  - Total length of the device or Mean length < 1km & Number of Groups < 10 – Install one (1) new fuse per group.
  - Total length > 80% of Total Protected Length – Install duplication of feeder relay or establish LV overcurrent (OC) relay.
  - Number of Groups = 1 – Install one (1) new recloser.
  - Total length < 10km – Install one (1) new recloser.
  - Largest Group length > 80% of the Total Length – Install one (1) new recloser.
  - Smallest Group length > 1km – Install a new recloser per group (Max of 3).
  - Smallest Group length < 1km – Manually determine the number of new reclosers (Max of 3).

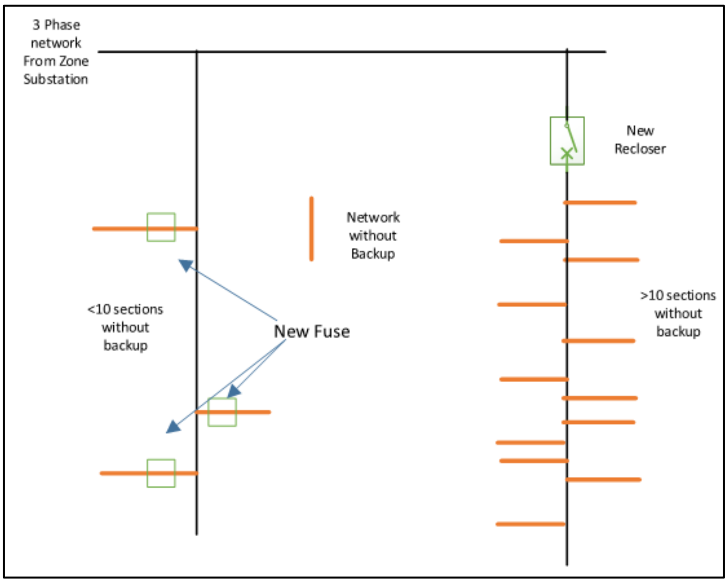

Figure 5 Proposed backup for 3 phase network from substation

- **Multiphase Network – Recloser is the existing main device**
  - Total length of the device or Mean length < 1km & Number of Groups > 10 – Install one (1) new recloser.
  - Total length of the device or Mean length < 1km & Number of Groups < 10 – Install one (1) new fuse per group.
  - Total length > 80% of Total protected Length – Install one(1) new recloser
  - Number of Groups = 1 – Install one (1) new recloser.
  - Total length < 10km – Install one (1) new recloser.
  - Largest Group length > 80% of the Total Length – Install one (1) new recloser.
  - Smallest Group length > 1km – Install a new recloser per group (Max of 3).
  - Smallest Group length < 1km – Manually determine the number of new reclosers (Max of 3).

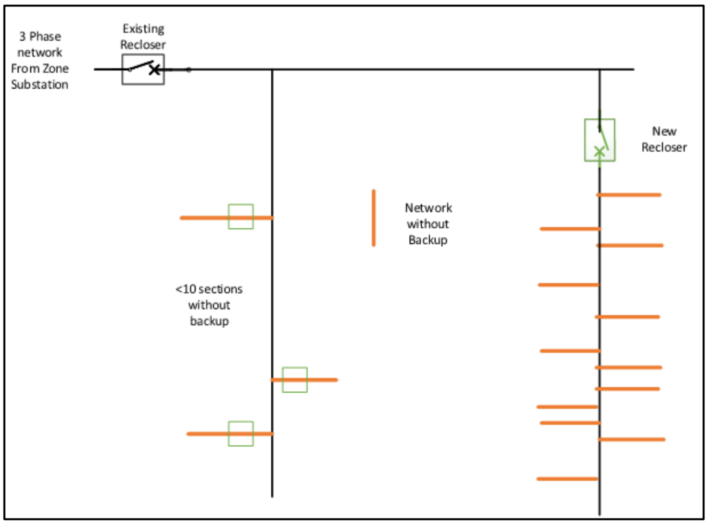

Figure 6 Proposed backup for 3 phase network from upstream recloser

Appendix I. Option 2 assumptions and criteria

Option 2 has the same assumptions and criteria as Option 1, with the following changes:

- **SWER Network – Relay is an existing backup device**
  - Fuses are not to be used on SWER Networks.
  - Total length for the device < 1km – Setting change to the upstream device.
  - Total length > 90% Total Protected Length – Set Negative Phase Sequence in the upstream device.
  - Number of Groups = 1 – Install one (1) new SWER recloser.
  - Total length for the device <10km – Install one (1) new SWER recloser.
  - Total length > 10km & Total length < 50% of Total Protected Length – Install the same number of SWER reclosers as groups (Max of 3).
  - Total length > 10km & Total length > 50% of Total Protected Length – Manually determine the number of SWER reclosers be installed.

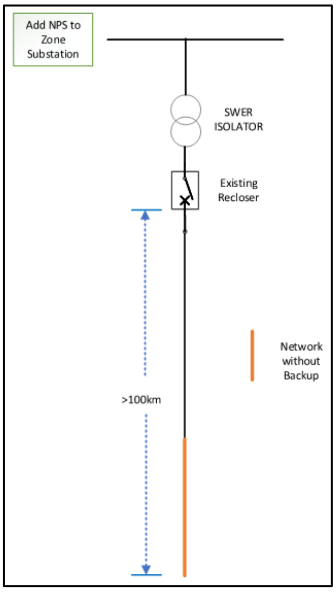

Figure 7 Alternate SWER backup (decreased reliability)

Appendix J. Option 3 assumptions and criteria

Option 3 has similar assumptions and criteria as Option 1 and 2, with the following differences:

- **SWER Network – Relay is an existing backup device**
  - The implementation of the Negative Phase Sequence will provide adequate backup protection to all downstream protection zones.

- **SWER Network – Three phase recloser is an existing backup device**
  - The implementation of the Negative Phase Sequence will provide adequate backup protection to all downstream protection zones.
  - Allowance for a number of large SWER networks requiring an additional SWER recloser. Network length > 50km.

- **SWER Network – SWER recloser is an existing backup device**
  - Fuses are not to be used on SWER Networks.
  - Total length for the device < 1km – Setting change to the upstream device.
  - Number of Groups = 1 – Install one (1) new SWER recloser.
  - Total length < 50% of Total Protected Length – Install the same number of SWER reclosers as groups (Max of 3).
  - Total length > 50% of Total Protected Length – Manually determine the number of SWER reclosers to be installed (Max of 3).

- **Multiphase Network – Relay is the existing main device**
  - Total number of backup zones is 718. Assume approximately half can be improved by the installation of a single three-phase recloser.
  - Approximately 20% of the zones can be improved by sections without fuse (known or unknown sizes).
  - Approximately 5% will require a relay.

- **Multiphase Network – Recloser is the existing main device**
  - All Phase faults will be solved by setting the Negative Phase Sequence in the upstream device.
  - All Earth faults will be solved by setting the Negative Phase Sequence or SEF in the upstream device.