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.

This document lays out the requirement for augmenting distribution feeder protection with backup protection schemes to improve fault clearance reliability, complying with the National Electricity Rules (NER) requirements. This document covers the backup protection requirements for Energex only.

There is a need for backup protection augmentation in Energex's network. This was identified through a current state assessment of Energex's distribution network, which evaluated the ability of the protection system to detect minimum fault levels on the distribution network. The assessment found 84 sites had inadequate back-up protection. Inadequate backup protection poses risks to Energex which 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

A 'Do nothing' option was rejected, as it could not address the compliance issues outlined above. Network options involving lowering the backup reach standards and splitting 11 kV busses were also considered but rejected due to safety and reliability risks. Three network options were evaluated in this business case:

Option 1 – Upgrade protection systems to achieve backup to Energex standards

Option 2 – Reconfigure the primary network to provide backup

Option 3 – Lower backup protection settings and shed load at peak times

Energex 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, based on the inadequate backup protection identified across the 84 sites within the Energex network.

To this end, Option 1 is the preferred option. It provides the most cost-effective means of addressing the inadequate backup protection at the 84 sites, in order to avoid breaching the NER. The option has a Net Present Value (NPV) of -$17.7M.

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
$18.9M	$0M	$18.9M

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 identifies the optimal capital investment necessary for implementation and upgrade of backup protection schemes to ensure reliable operation of the protection system.

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 Energex 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 National Electricity Rules (NER) requirements. This document is in line with the EQL Asset Management Plan (AMP) – Protection Relays.

1.3 Identified Need

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

Energex 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 across the 84 sites within the Energex network.

A current state assessment of Energex's distribution network has been undertaken based on the ability of the protection system to detect minimum fault levels on the distribution network. This assessment resulted in 84 sites found to have inadequate back-up protection.

The main benefits to establishing backup protection are:

- Compliance with NER requirements for power system protection.
- Increased safety by ensuring faults are cleared from the distribution network.
- Provide reliability benefits by creating more protected sections that can be independently isolated during system faults.

- The ability to perform maintenance on primary protection devices and maintain adequate protection for energised networks.

1.4 Energy Queensland Strategic Alignment

Table 1 details how the backup reach program contributes to Energex'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 Energex's equipment. Backup protection can reduce planned outages by allowing Energex 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 Energex'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 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 Energex 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 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)	Existing protection schemes at the 84 identified sites 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 equipment damage or safety concerns. Improved protection schemes will help reduce the impact of the above to reasonable levels

[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
		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

Energex has network protection standards and setting calculation methodologies, aligned with industry practice, which provide guidelines to protection engineers to ensure 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.

A survey of distribution feeders was undertaken by the Network Planning Department at Energex and 84 sites were found to have backup protection which did not meet the applicable network protection standard.

Clause S5.1.9(f) of the NER requires that the power network have two independent forms of protection that can detect and clear all credible fault scenarios in the distribution network. The NER rules requiring backup protection were introduced in 2003. Energex has been installing or upgrading backup protection in the network for some time, however previous processes were to correct backup protection issues as they were identified. New tools and programs have allowed an assessment of the full network, and a network wide program of works is more cost-efficient and can engineer the risks of inadequate backup protection out of the network by 2025.

The Lakes Creek Zone Substation (March 2017) is an example where the primary protection failed to operate, and backup protection was required to clear the fault, but was unable to. 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.

Energex 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 to identify backup protection reach issues. 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.

Across the Energex network there have been a significant number of failed in service devices from 2013 until 2018. Over this period an average of 71 relays failed in service per year, which can be extrapolated to 710 relays in a 10-year period. Where a relay fails in service there may be no protection in place up until the point the relay is discovered to have failed. A fault occurring on any of the affected networks before this point will be slow clearing or not cleared automatically if there is no backup protection, which poses a significant safety and compliance risk. Older mechanical relays, and some electromechanical relays, are unable to communicate remotely that they have failed. Many newer relays can fail in ways that are not detectable until testing. Due to these limiting factors it is not cost effective or practical to rapidly identify when a relay has failed in service, therefore it is more practical to install backup protection given the safety, plant damage, and unserved energy risks associated with a fault occurring where the primary protection relay has failed.

Appendix G lists the minimum backup reach for each of the 84 substations, as well as the length of conductor not backed up and the maximum fault level that non-backed up assets may experience at each substation. On average, 34km of conductor per substation does not have adequate back coverage, with an average maximum fault level of 3.7kA, which increases up to 9.0kA at the worst substation. Whilst not all the conductor at risk will be exposed to fault levels of this magnitude, fault levels will usually exceed conductor ratings if the fault is not cleared due to lack of backup protection. For a fault on these feeders where the primary protection fails to clear, the fault level puts significant amounts of equipment at risk of damage which breaches NER requirements (S5.1a.8(a) and table S5.1a.2).

2 Counterfactual Analysis

2.1 Purpose of asset

Energex'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 duration of the fault whilst also minimising the amount of network isolated to clear the fault. Protection schemes need to be robust enough 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 Energex 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 Energex'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 Energex's staff. Uncleared faults that cause damage leading to extended outages or to fatalities may lead to sizeable fines and reputational damage to Energex.

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 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, that the substation has the required primary plant (for example, a spare Current Transformer (CT)) to integrate the protection relay into the site
- A backup reach ratio (maximum fault current/pickup) in alignment with Energex protection standards is required to reliably clear faults

2.3 Risk assessment

The following risks 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

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	5 *(Single fatality)*	2 *(Very unlikely)*	**10** ***(Low)***	2019
Failure of a protection service at a Commercial & Industrial (C&I) substation and subsequent network fault causes a fire resulting in **multiple fatalities**.	Safety	6 *(Multiple fatalities)*	2 *(Very Unlikely)*	**12** ***(Moderate)***	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

In addition to the counterfactual, two other categories of options were considered but rejected:

Lower the backup protection requirements

The following options to reduce the need for backup protection were considered but rejected on the basis of safety, cost, complexity or risk of non-controlled outage.

- Reduce the backup reach target in the protection standard, which is presently 1.5, to 1.3. Not suitable for some older relays that are significantly less accurate and reliable than modern relays.
- Implement load encroachment logic to allow the protection pickup to be set below the prospective standing load current. Energex is concerned that this technology may not be reliable and mal-operations may occur, putting significant load at risk which is unacceptable.

Splitting 11kV busses

The following option is rejected as a whole-of-network solution due to load or reliability requirements but may be an available option at some sites dependent on site-specific analyses. It has been considered as part of Option 1:

- Where two 33/11kV transformers are operating in parallel, split the 11kV busses to allow transformer 11kV overcurrent protection to see more fault current, effectively increasing protection reach (up to double) without adjusting settings.

3.2 Identified options

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
- Circuitry changes to modify existing device functionality

Option 1 – Upgrade protection systems to achieve backup to Energex standards

Under this option, protection systems at each of the 84 sites in question will be upgraded to achieve backup to Energex standards. The most economical option (or combination of options) from a suite of potential measures will be chosen. Options to provide backup include:

- Enabling negative phase sequence (NPS) in existing relay, or installing a new relay with NPS protection capability. Unlike Ergon’s network, which has significant quantities of single wire earth return (SWER) network) enabling NPS to provide comprehensive backup, Energex’s network is multiphase and balanced. As NPS cannot detect balanced network faults, it is less effective for Energex.

  NPS does, however, provide improvement where it is applied to detect unbalanced phase and earth faults in that it will provide approximately 15% more sensitive backup than phase. overcurrent (OC). This allows improved backup and the OC can be increased, reducing risk of operation due to load.

- Change other protection relay settings, for example transformer 11kV OC, which are typically used to provide backup. Adjusting this setting will improve backup but needs to consider substation load.
- Installation of line fuses on network spurs with low fault levels and low installed capacity
- Pole mounted reclosers on 11kV feeders to reduce the required reach of feeder primary and backup protection relays at the substation. This has the benefit of utilising existing relays for backup thus reducing cost.
- Duplication of feeder protection relays at the substation
- Installation of bus overcurrent (BOC) protection, which improves backup by backing up a single bus only, rather than all substation busses per the traditional phase OC. The main drawback for BOC schemes is that new CTs are often required to be installed, which can lead to high installation costs (including extended outages) making BOC non-economical compared to other options. Additionally, for older substations, establishing BOC protection is prohibitively expensive due to the requirement for a total substation outage lasting more than two days. Installation of mobile generation to provide for the significant amount of load shed during a substation outage is prohibitively expensive.

Each of the 84 sites was reviewed to understand the minimum, specific works that were required to provide backup protection. Site specific optioneering has been completed by EQL to select the minimal cost viable option for providing backup protection. The number and type of augmentations required are detailed in Table 4 below.

Table 4 Solution types identified to provide backup

Solution Method	Total (no.)
Setting Change (enable NPS and/or adjust OC)	58
Circuitry Change	47
Line Fuse installed	19
Three Phase Recloser installed	15
Protection relay upgrades (duplication or other)	564
Reconductoring	280 (metres)

The most economical solution will vary depending on the circumstances at each individual site. To illustrate this, example extracts from the Project Approval Reports are shown in Table 5.

Table 5: Extract of approach for Option 1.

Substation Name	Options Rejected	Proposed Solution
Mudgeeraba West Package (MGP)	• Splitting 11kV bus. 11kV bus is already split. • Bus overcurrent. Load is too high compared to minimum fault level.	Duplicate several feeder relays, install a pole mounted recloser. Bundle project with replacing obsolete relays.
Wivenhoe (WHO)	• Bus overcurrent. Rejected as more expensive option. This would still require two additional line reclosers due to fault levels being significantly below load current, and there is no existing room to fit new relays at the substation	Install three pole-mounted reclosers.

Substation Name	Options Rejected	Proposed Solution
Jimboomba (JBB)	• Splitting 11kV bus. 11kV bus is already split. • Bus overcurrent. Load is too high compared to minimum fault level.	Install seven duplicate relays. Bundle project with replacing 23 end of life relays.
Meeandah (MDH) & Hamilton Lands (HTL)	• Bus overcurrent at MDH. Load is too high compared to minimum fault level and was deemed to be significantly more expensive due to works required.	Duplicate protection relays at MDH and bundle project with replacing end of life relays. At HTL, lower transformer low voltage (LV) settings to provide backup. Load is not an issue at this substation compared to minimum fault.
Zillmere (ZMR)	• Bus overcurrent. Load is too high compared to minimum fault level. Cost is expensive due to requiring CTs installed to accommodate bus overcurrent protection.	Duplicate relays on 10 feeders. Bundle with replacing obsolete relays.
Kallangur (KLG)	• Bus overcurrent. Rejected due to cost. Many relays at this site are already being replaced due to end of life, which requires work on the entire 11kV panel. The cost to duplicate relays is therefore minimal in addition, compared to the cost of taking the bus out of service and installing new CTs for bus overcurrent.	Duplicate relays on the 11kV feeders and replace the obsolete existing relays.

Option 2 – Reconfigure the primary network to provide backup

When backup cannot be achieved, it is typically due to a combination of high load and low fault levels. This option aims to provide backup by increasing fault levels by reducing the length and/or impedance of 11kV feeders, which in turn will enable backup to be provided.

Under this option, 11kV busses at each substation in question will be split to enable improved backup. New zone substations will be constructed in the vicinity of substations where backup cannot be achieved, and portions of existing 11kV feeders will be transferred to these substations. The benefit of the new zone substation is twofold:

- Forecast load will be reduced at existing substations, enabling protection settings to be lowered, and enabling backup to be achieved.
- 11kV feeders will be shorter, meaning that the minimum fault level to be backed up will be reduced, enabling backup to be achieved.

Option 3 – Lower backup protection settings and shed load at peak times

In Energex’s network, operation of a protection system designed to provide backup to substation 11kV feeder protection systems will usually cause loss of supply to at least one 11kV bus or possibly the substation. Backup protection systems are therefore set to allow peak load to flow without operating.

Forecast peak load may only occur for a short period of time (hours) in a single year, therefore backup protection settings could be lowered significantly to achieve backup, while remaining above load most of the time. Under this option it is proposed to:

- Lower backup protection settings at each of the 84 identified sites to the forecast 10PoE load per backup device to enable backup protection to be achieved

- Under scenarios where substation load is set to exceed protection settings, use automated systems to 11kV shed load by opening 11kV feeder CBs and avoid a total outage at the substation and maintain as much load in service as possible.
- If the 10% Probability of Exceedance (10PoE) load is high enough that settings cannot be lowered sufficiently to achieve backup, other measures will be required to address the remaining backup risk.

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 assessment of each option

Capital Costs (CAPEX)

The number of substations proposed to be remediated in each financial year are shown in Table 6.

Table 6: 2020-25 portion Delivery Time Line

	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Substations Addressed	25	14	16	17	12	84

Option 1 – Upgrade protection

Costs are summated from the estimates in the site-specific Project Approval Reports, where available, and ellipse estimates where not. Full breakdown can be found in these internal Energex documents, referenced in Appendix G. Unit estimates are provided in Appendix H.

Option 2 – Reconfigure network

Cost assumes the same number of substations being addressed per year as Option 1, with two busses assumed per substation and some reconductoring required. A single new zone substation will provide benefit to other adjacent substations; therefore, it is estimated that, on average, an additional zone substation will be required for every four substations requiring changes to achieve backup, at an estimated cost of $15M each.

Option 3 – Lower backup settings and shed load

Cost assumes the same number of substations being addressed per year as Option 1. Capital works required are as follows:

- Supervisory Control and Data Acquisition (SCADA) upgrades for automatic load reduction - $50,000 per substation
- Calculation of new transformer 11kV OC settings, and application of settings on site - $10,000 per site
- A sample analysis has found that although this approach reduces the number of non-compliances, it is likely, that on average, some 11 kV feeders will still be non-compliant with backup standards after this measure has been implemented. Substation works are already being carried out under this option (SCADA upgrade) it is assumed that the best option will be

to duplicate 11kV feeder relays on the feeders in question, at an average cost of $48,700 per relay (252 relays total).

- It's assumed that some introductory works will be required – as this is a major change to how the network is operated contingency plans and operational procedures will need to be updated, and new relay standards developed (multi-group applications) so that the full substation load can be carried by a device under contingency scenarios – for example, if one transformer is out of service. This is estimated to be an average of $100,000 per year over the 5-year period.
- It is understood that this option does not provide an acceptable standard in that "by design" some customer load shedding will routinely occur. However, it is a valid technical and economic option to be considered.

The direct cost for each option is shown in Table 7. The cost summary is in real $2018/19 dollars.

Table 7: 2020-25 Cost Summary

Option	2020/21	2021/22	2022/23	2023/24	2024/25	Total
1	$5.4M	$3.9M	$5.1M	$2.6M	$1.9M	$18.9M
2	$94.3	$52.8M	$60.3M	$64.1M	$45.2M	$316.7M
3	$6.5M	$3.7M	$4.2M	$4.5M	$3.1M	$22.0M

High-Level Risk Quantification

The value of risk in each option as a result of customer outage, with reference to AEMO standards for Value of Customer Reliability (VCR) was quantified at a high-level for each option in this business case.

The VCR value used in this analysis is $39.71/kWh, with a range of $27.80/kWh to $51.62/kWh. These are the aggregate weighted average values for Queensland.

The following key assumptions were used to drive this analysis:

- **Option 1:** Protection upgrades reduce risk of feeder failure due to inadequate backup to a negligible level.
- **Option 2:** Installation of new zone substations, reducing load at existing sites and increasing minimum fault levels, will enable backup protection to be set to Energex standards and reduce risk of feeder failure due to inadequate backup to a negligible level.
- **Option 3:** Under Option 3, it's proposed to set backup protection devices to the 10PoE load of the substation. By definition this means that once every 10 years this forecast will be exceeded. At this point the load shed system will be required to operate. It's assumed that a single 11kV feeder, with a load of 4MVA, will be opened for 2 hours to address this peak demand, at 10% of sites where the scheme has been rolled out each year.

  In addition, the lowered backup settings are below contingency load, meaning that if a transformer is taken out of service under fault, the other transformer will also trip under OC protection. It is assumed that, over the 5-year period, 0.5 transformers per year in the population at the 84 substations will fail, causing total loss of a substation. Based on a sample of forecast data, it is assumed that the magnitude of load loss will be 25MVA and will occur for one hour.

Table 8: Annual cost of outage under each option

Option	Annual cost of outage ($/year)		
	Average	Minimum	Maximum
Option 1: Upgrade protection systems	$0	$0	$0
Option 2: Upgrade primary network	$0	$0	$0
Option 3: Reduce backup settings and shed load	$2,243,615	$1,918,200	$3,561,780

Results

Table 9 below contains the results of a 10-year Net Present Value (NPV) analysis of the identified options. The NPV of each option, along with the Present Value (PV) of costs and benefits is outlined in Table 9, each discounted at the Regulated Real Pre-Tax Weighted Average Cost of Capital (WACC) rate of 2.62% over the 30-year study period from 2019/20 to 2039/40. This table confirms that Option 1: Upgrade Protection has the highest NPV and is therefore the preferred option from an economic perspective.

Table 9: Net present value of options

Option	Net Present Value ($M)	PV of CAPEX ($M)	PV of Outage Impacts ($M)
Option 1: Comprehensive backup protection	-$17.70	-$17.70	-$0.00
Option 2: Upgrade primary network	-$282.08	-$282.08	-$0.00
Option 3: Reduce backup settings and shed load	-$30.91	-$20.52	-$10.39

3.4 Scenario Analysis

3.4.1 Sensitivities

Sensitivity analysis was carried out on CAPEX costs for this case, with sensitivities of +/- 20% on all base CAPEX rates tested.

Table 10 outlines the results of this analysis. Option 1 was the most cost-effective option, due to its low up-front capital cost and ability to reduce risk of customer outage within Energex networks. Under the unlikely scenario that option 1 is 20% more expensive and option 3 is 20% less expensive, option 3 may become more economical over the 5-year period. However, there will be an on-going annual VCR cost of approximately $2M due to shed and lost load, as well as impacts to SAIDI and SAIFI numbers. Taking these risks into account option 1 remains the most cost-effective.

Table 10: Sensitivity Analysis Results

Options	Base NPV ($M)	CAPEX rate sensitivity	
		+20%	-20%
Option 1	$17.7	$21.2	$14.2
Option 2	$282.1	$338.5	$225.7
Option 3	$20.52	$24.62	$16.40

3.4.2 Value of regret analysis

In terms of selecting a decision pathway of 'least regret', Option 1 presents an economically efficient balanced approach to investment by targeting backup protection works based on cost and reliability assessments and reducing risk to the greatest extent without bringing forward unnecessary expenditure. Option 3 may result in higher cost of unsupplied load if actual load is higher than forecast, resulting in larger than anticipated load reductions.

The key regrets identified in this business case are:

- Uncleared or slow clearing fault on the 11kV 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 Energex in breach of the NER section 5.1.9.
- Critical loads are removed from the network, having unforeseen consequences – for example, disabling customer medical equipment, or accidents due to traffic lights out of service.

Load growth in the network, or lack of it, has been taken into consideration for determining the suitability of options as part of the analysis for Option 1 and Option 3. It's assumed that the installation of new zone substations (Option 2) will address any potential risks posed by increased load for that option. If load is forecast to increase significantly, then Option 3 will become less advantageous.

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 11 below details the advantages and disadvantages of each option considered.

Table 11 Qualitative assessment of options

Options	Advantages	Disadvantages
Option 1 – Upgrade protection to achieve backup	• Addresses risk associated with uncleared faults • Brings whole of network into compliance with the NER and QLD electrical safety regulations • Improves safety of the public across Energex's network • Potentially reduces SAIDI and SAIFI numbers due to reducing amount of network isolated during a fault, and reducing risk of damaged equipment extending fault duration. • Can be bundled with other asset management projects such as relay replacements due to age, or circuit breaker replacements.	• Higher on-going maintenance costs due to increased number of protection relays.

Options	Advantages	Disadvantages
Option 2 – Reconfigure the network	• Addresses risk associated with uncleared faults • Brings whole of the network into compliance with the NER and QLD electrical safety regulations • Improves safety of the public across Energex's network • Potentially reduces SAIDI and SAIFI numbers due to more and shorter 11kV feeders.	• High cost, and higher ongoing maintenance costs due more equipment on the network
Option 3 – Lower backup settings and reduce load	• Addresses risk associated with uncleared faults • Brings whole of network into compliance with the NER and QLD electrical safety regulations	• Increases SAIDI and SAIFI numbers by planning to de-energise load at peak times. • In multi-transformer substations, loss of a single transformer will cause a total loss of supply due to reduced backup settings • May have consequences for public safety e.g. customer medical equipment which requires grid supply out of service, traffic light outages etc. • Reduces operational flexibility e.g. capacity to be able to switch load between zone substations during contingency situations • Load shed at peak times (typically periods of hot weather) unlikely to be well received by customers, damaging Energex's reputation • Setting protection settings below contingency load is poor practice.

3.5.2 Alignment with network development plan

One of the core focusses of Energex'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 Energex 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 Energex's business as usual replacement planning functions.

3.5.3 Alignment with future technology strategy

This program of work does not contribute directly to Energy Queensland's transition to an Intelligent Grid, in line with the Future Grid Roadmap and Intelligent Grid Technology Plan. However, it does support 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 12: Risk assessment showing risks mitigated following Implementation

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	*(Original)* *5* *(Single fatality)* (Mitigated) 5 *(As above)*	 *3* *(Unlikely)* 1 *(Almost no likelihood)*	 ***15*** ***(Moderate)*** **5** ***(Very Low)***	2019
Failure of an 11kV feeder protection relay to operate following a 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 **multiple fatalities**.	Safety	*(Original)* *6* *(Multiple fatalities)* (Mitigated) 6 *(As above)*	 *2* *(1 in 10,000)* 1 *(Almost no likelihood)*	 ***12*** ***(Moderate)*** **6** ***(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 to upgrade protection systems to Energex standards at all 84 identified sites where it has been identified that there is inadequate backup protection, for a cost of:

Table 13: Identified costs for preferred option

Direct Approved Value	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Option 1	$5.4M	$3.9M	$5.1M	$2.6M	$1.9M	$18.9M

4.2 Scope of preferred option

Appendix G lists the proposed sites for augmentation and their proposed implementation date. For cost-effectiveness, projects are bundled with Repex relay replacements. Each site was reviewed to understand the minimum, specific works that were required to provide backup protection. The full scope of each can be found in the relevant Project Approval Reports.

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).*

AEMO, *Value of Customer Reliability Review, Final Report,* (September 2014).

Energex, *Distribution Annual Planning Report (2018-19 to 2022-23) [7.050]*, (21 December 2018).

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

Energy Queensland, *Asset Management Plan, Protection Relays [7.038]*, (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).

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
ALARP	As Low as Reasonably Practicable
AMP	Asset Management Plan
Augex	Augmentation Capital Expenditure
BAU	Business as Usual
BoC	Bus overcurrent
C&I	Consumer and Industrial (substation)
CAPEX	Capital expenditure
CB	Circuit Breaker
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
DC	Direct Current
DNSP	Distribution Network Service Provider
EQL	Energy Queensland Ltd
HTL	Hamilton Lands (substation)
HV	High Voltage
IT	Information Technology
JBB	Jimboomba (substation)
KLG	Kallangur
KRA	Key Result Areas
kV	Kilovolt
LV	Low Voltage
MDH	Meeandah (substation)
MGP	Mudgeeraba West Package (substation)

Abbreviation or acronym	Definition
MSS	Minimum Service Standard
MVA	Megavolt Ampere
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules (or Rules)
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
SFAIRP	So Far as Is Reasonably Practicable
VCR	Value of Customer Reliability
WACC	Weighted average cost of capital
WHO	Wivenhoe (substation)
ZMR	Zillmere
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 14: 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 1.6 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).

Capital Expenditure Requirements	Rationale
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 1.4 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 15: 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)	$18.90
Business Case Value	
(M$2020)	$19.66

Appendix G. Proposed projects for Option 1

The projects currently planned for Option 1 (proposed) are shown below.

Substation	Min Protection Reach	Fault level at minimum reach (kA)	Length of conductor not protected (km)	Proposed Date
MGP MUDGEERABA WEST PKG - Improve 11kV Backup Protection Reach and Replace End of Life Protection Relays	0.491	1.65	55.01	08-Jul-2020
WHO WIVENHOE - Improve 11kV Backup Protection Reach	0.813	1.20	41.89	17-Jul-2020
JBB - Install Transformer POPS, deload substation to SSLGV, improve backup protection and replace end of life relays	0.621	2.40	86.50	03-Sep-2020
MDH - MEEANDAH Improve 11kV Backup Protection Reach	0.803	6.00	37.99	22-Feb-2021
ZMR - ZILLMERE Improve 11kV Backup Protection Reach	0.384	6.00	71.25	26-Feb-2021
KLG - KALLANGUR Improve 11kV Backup Protection Reach	0.532	6.31	63.79	30-Mar-2021
QPT - QUEENSPORT Improve 11kV Backup Protection Reach	0.703	6.30	15.61	13-Apr-2021
TRP TARAMPA - Improve 11kV Backup Protection Reach	1.022	0.78	17.15	28-Apr-2021
SPE - STRATHPINE Improve 11kV Backup Protection Reach	0.001	6.00	22.00	26-May-2021
IDY Indooroopilly - Improve 11kV Backup Protection Reach	0.001	6.00	11.77	27-May-2021
CPL Coopers Plains - Improve 11kV backup protection reach and replace end of life equipment CB3X12	0.568	6.00	34.89	11-Jun-2021
DRD - DUFFIELD ROAD Improve 11kV Backup Protection Reach	0.460	6.00	50.24	16-Jun-2021
AHL - ARANA HILLS Improve 11kV Backup Protection Reach	0.449	6.00	78.89	23-Jun-2021
NDH - NUNDAH Improve 11kV Backup Protection Reach	0.784	4.80	16.07	24-Jun-2021
DBY - DECEPTION BAY Improve 11kV Backup Protection Reach	0.497	4.80	63.47	28-Jun-2021
HDN HELIDON - Improve 11kV Backup Protection Reach	0.887	0.75	10.93	30-Jun-2021
MLB - Improve 11kV Backup Protection Reach & Repl BC	0.779	3.60	52.00	30-Jun-2021

Substation	Min Protection Reach	Fault level at minimum reach (kA)	Length of conductor not protected (km)	Proposed Date
CGS Transformer BU Protection	C&I TFMR Backup	-	-	30-Jun-2021
MAK Transformer BU Protection	C&I TFMR Backup	-	-	30-Jun-2021
NME Transformer BU Protection	C&I TFMR Backup	-	-	30-Jun-2021
PHS Transformer BU Protection	C&I TFMR Backup	-	-	30-Jun-2021
QNP Transformer BU Protection	C&I TFMR Backup	-	-	30-Jun-2021
WGC Transformer BU Protection	C&I TFMR Backup	-	-	30-Jun-2021
CHS Transformer BU Protection	C&I TFMR Backup	-	-	30-Jun-2021
MHS Transformer BU Protection	C&I TFMR Backup	-	-	30-Jun-2021
WSO - WACOL SOUTH Improve 11kV Backup Protection Reach	0.622	6.00	25.55	19-Jul-2021
WFD - WOODFORD Recover TR2, Improve 11kV Backup Prot Rch & repl isolators	0.495	1.80	79.21	30-Sep-2021
VSL - VARSITY LAKES Improve 11kV Backup Protection Reach	0.611	6.00	60.33	20-Apr-2022
CMD - CURRIMUNDI Improve 11kV Backup Protection Reach	0.801	3.60	32.34	27-May-2022
SHW - SHERWOOD Improve 11kV Backup Protection Reach	0.532	6.00	17.90	31-May-2022
MTG MT GRAVATT - Improve 11kV Backup Protection Reach	0.403	6.00	50.00	22-Jun-2022
BKD - BIRKDALE Improve 11kV Backup Protection Reach	0.390	6.00	61.21	30-Jun-2022
BLH - BEENLEIGH Improve 11kV Backup Protection Reach	0.367	6.00	68.37	30-Jun-2022
BTA - BETHANIA Improve 11kV Backup Protection Reach	0.509	4.46	60.82	30-Jun-2022
CRM CRESTMEAD - Improve 11kV Backup Protection Reach and Replace Protection Relays	0.244	6.00	74.75	30-Jun-2022
HWD HEATHWOOD - Improve 11kV Backup Protection Reach and Replace Protection Relays	0.404	5.11	51.70	30-Jun-2022

Substation	Min Protection Reach	Fault level at minimum reach (kA)	Length of conductor not protected (km)	Proposed Date
LLY - LAIDLEY Improve 11kV Backup Protection Reach	0.623	0.90	53.00	30-Jun-2022
WNM - WYNNUM Improve 11kV Backup Protection Reach	0.718	4.50	32.96	30-Jun-2022
WRG - Improve 11kV Backup Protection Reach	0.504	3.00	61.95	30-Jun-2022
GVN Gaven - Improve 11kV Backup Protection Reach	0.420	6.00	61.30	04-Jul-2022
LBS - LYTTON B Improve 11kV Backup Protection Reach	0.795	6.00	17.70	15-Jul-2022
BBS Belmont - Improve 11kV backup protection reach	1.467	1.80	0.73	06-Oct-2022
BLB- BULIMBA Improve 11kV Backup Protection Reach	0.787	4.20	13.81	22-Mar-2023
ALY - ANNERLEY Improve 11kV Backup Protection Reach	0.601	6.00	21.07	24-May-2023
MFD - MORAYFIELD Improve 11kV Backup Protection Reach	0.420	4.82	75.61	24-May-2023
NRA - NARANGBA Improve 11kV Backup Protection Reach	0.325	6.00	74.88	31-May-2023
ARG Acacia Ridge - Replace Protection Relays and Improve 11kV Backup Protection Reach	0.474	6.00	18.72	27-Jun-2023
BHD BURLEIGH HEADS - Improve 11kV Backup Protection Reach and Replace End of Life Relays	0.755	3.60	63.57	30-Jun-2023
ARL - ARUNDEL Improve 11kV Backup Protection Reach	3.559	1.20	0.00	30-Jun-2023
BVL BOOVAL- Improve 11kV Backup Protection Reach	0.608	4.80	32.27	30-Jun-2023
DBS - Improve 11kV Backup Protection Reach & Repl BC	0.874	6.00	6.98	30-Jun-2023
GLY - GROVELY Improve 11kV Backup Protection Reach	0.446	6.00	58.26	30-Jun-2023
MMC - MERRIMAC Improve 11kV Backup Protection Reach	0.715	3.60	24.46	30-Jun-2023
MTB MT TAMBORINE - Improve 11kV Backup Protection Reach	0.380	2.11	91.59	30-Jun-2023
TGW Toogoolawah - Improve 11kV backup protection reach	0.611	0.57	64.84	30-Jun-2023

Substation	Min Protection Reach	Fault level at minimum reach (kA)	Length of conductor not protected (km)	Proposed Date
SMF - SAMFORD Improve 11kV Backup Protection Reach	0.349	3.60	48.48	15-May-2024
IPS - IPSWICH SOUTH Improve 11kV Backup Protection Reach	0.574	3.00	41.60	06-Jun-2024
BDA - BURANDA Improve 11kV Backup Protection Reach	0.673	6.00	10.88	17-Jun-2024
SPF - SPRINGFIELD Improve 11kV Backup Protection Reach	0.728	6.00	52.38	20-Jun-2024
MHL - MANGO HILL Improve 11kV Backup Protection Reach	0.377	3.00	90.63	26-Jun-2024
RLA ROCKLEA - Improve 11kV Backup Protection Reach and Replace Protection Relays	0.848	3.60	7.83	27-Jun-2024
BIS - BRIBIE ISLAND Improve 11kV Backup Protection Reach	0.494	3.96	30.33	30-Jun-2024
BRT - BRIGHTON Improve 11kV Backup Protection Reach	0.810	3.60	12.84	30-Jun-2024
CHL CAMP HILL - Improve 11kV Backup Protection Reach and Replace Protection Relays	0.823	3.00	37.60	30-Jun-2024
CNB - CORNUBIA Improve 11kV Backup Protection Reach	0.410	3.00	27.62	30-Jun-2024
CRB - CURRUMBIN Improve 11kV Backup Protection Reach	0.827	3.54	19.22	30-Jun-2024
ENG - ENOGGERA Improve 11kV Backup Protection Reach	0.674	5.25	19.01	30-Jun-2024
IPL - INNISPLAIN Improve 11kV Backup Protection Reach	0.800	0.58	82.06	30-Jun-2024
LGL - LOGANLEA Improve 11kV Backup Protection Reach	0.585	6.00	26.61	30-Jun-2024
SPO - SOUTHPORT Improve 11kV Backup Protection Reach and Replace End of Life Relays	0.930	3.60	17.23	30-Jun-2024
STT - STAPYLTON Improve 11kV Backup Protection Reach	0.400	6.00	26.05	30-Jun-2024
CPS Capalaba South - Improve 11kV Backup Protection Reach	0.413	6.00	37.08	16-Jul-2024
PRG -POSTMANS RIDGE Improve 11kV Backup Protection Reach	0.724	0.58	6.39	21-May-2025
ESK Improve 11kV Backup Protection Reach	1.247	0.40	4.55	23-May-2025

Substation	Min Protection Reach	Fault level at minimum reach (kA)	Length of conductor not protected (km)	Proposed Date
THL - TENTHILL Improve 11kV Backup Protection Reach	1.045	0.58	7.82	23-May-2025
EMP Eight Mile Plains - Replace 11kV CBs, Obsolete Relays and Improve backup Protection	0.550	3.02	36.85	30-Jun-2025
ABY - AMBERLEY Improve 11kV Backup Protection Reach	0.721	3.00	27.94	30-Jun-2025
BLN - BEENLEIGH NORTH Improve 11kV Backup Protection Reach	1.116	3.96	4.36	30-Jun-2025
CPR COORPAROO - Improve 11kV Backup Protection Reach	1.111	3.00	4.15	30-Jun-2025
CVL - CLEVELAND Improve 11kV Backup Protection Reach	0.467	3.00	55.55	30-Jun-2025
HTN - HAMILTON Improve 11kV Backup Protection Reach	0.477	4.80	25.49	30-Jun-2025
MCW - Improve 11kV Backup Protection Reach	0.855	2.40	30.86	30-Jun-2025
MGL - MOGGILL Improve 11kV Backup Protection Reach	0.505	3.84	34.16	30-Jun-2025

Appendix H. Estimated unit costs for protection schemes

Solution	Typical Cost (per unit)	Comments
Protection relay settings change	$5,000	Transformer LV OC protection settings must be adequate for the substation 10% PoE peak demand forecast load with one transformer out of service.
Installation of master drop out fuses (MDOs)	$15,000 to $25,000 per MDO installation	Protection grading cannot always be achieved with upstream protection devices for phase to ground faults. Fuse protection does not provide remote indication of fault or auto-reclose functionality resulting in transient faults to cause an extended interruption of supply to customers.
Install Bus Overcurrent Bus Earth Fault (BOC/BEF) protection scheme	$150,000 to $350,000 per additional relay	Requires protection CTs (or space available) to be installed in the bus section circuit breaker panel/bay. Bus overcurrent protection scheme only required per 11kV bus zone rather than on multiple 11kV feeders per bus zone. These estimates do not include the cost for a bus or total substation outage as these are dependent on amount of load supplied by the bus or substation.
Installation additional feeder protection relay	$70,000 to $125,000 per additional relay	
Installation of Automatic Circuit Recloser	$100,000 to $150,000 per ACR installation	3 phase fault level at proposed ACR location to be lower than 2.5kA for normal grading and discrimination based on "Planning Protection Guidelines for Protection". Typical 11kV bus 3 phase fault levels at Energex Urban zone substations are in the order of 8-10kA when two transformers operated in parallel. Typically no more than three (3) ACRs to be installed in series on a feeder.
Reconductoring existing feeder sections	As required for length	This is typically relatively expensive as large lengths of conductor are required to be changed to alter the fault level significantly enough to increase the fault level to enable backup reach protection to be sufficient.