Business Case
Protection Upgrades to Support Increasing Distributed Energy Resources

Part of the Energy Queensland Group

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.

Distributed Energy Resource (DER) penetration in the distribution network is increasing. Within Energy Queensland (EQL) networks, 40 sub-transmission substations, 232 zone substations, and 645 distribution feeders are already experiencing reverse power flow caused by high DER penetration. This puts the network at risk of reverse-energised earth faults on the sub-transmission network that cannot be detected and isolated with existing protection schemes, posing an unacceptable safety risk. In addition, there is a risk of incorrect Under Frequency Load Shedding (UFLS) operation impacting the reliability and stability of the network. Instances of these risks have occurred on the Ergon Energy network within the last 5 years. Due to the network topologies, load densities, sub-transmission protection systems and historical programs of work, the Energex network is not identified as having the same exposure for protection systems being affected by DER. Thus, the problems and solutions identified in this report are only intended for the Ergon Energy network.

A counterfactual, 'do nothing' option was considered and rejected, along with several options to either limit customer exports to the grid or carry out augmentation works for individual small customers. Restricting the amount of generation in the distribution network is unacceptable as customers have an expectation of being able to connect DERs to the network and would not accept being limited to a first come first serve basis, and bespoke augmentation works are likely to be prohibitively expensive. Two network options were evaluated as part of this business case:

Option 1 – Installation of inter-tripping at 20 sites and NVD protection at 20 sites, and a UFLS pilot project at a sole location to address the risks caused by increasing DER penetration

Option 2 – Installation of NVD protection at 40 sites, and UFLS upgrades at all substations with reverse power flows.

Energy Queensland 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), customer reliability and preparing the network for the ongoing adoption of new technology by customers (e.g. solar PV). In this business case network safety risk mitigation is a strong driver, due to the need to address reverse flow issues across the Ergon Energy network arising from the increased uptake of DER by customers.

To this end, Option 1 is the preferred option in both cases. It provides the most cost-effective means of addressing the identified network safety risks while still enabling customers to participate un-curtailed in the grid through their DER. The Net Present Value (NPV) of this option is -$4.7M.

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
N/A	$0	$6M

Note the original Regulatory Proposal bundled DER protection schemes with those for SEF and Diverse Communications, and as such there is not an applicable original direct cost for this business case from the Regulatory Proposal submissions.

Contents

1. Introduction

Protection systems ensure the safe and reliable functioning of the power network during power system abnormalities. The primary function of protection systems 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 for 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.

1.1 Purpose of document

This document recommends the optimal capital investment necessary for implementation of new protection schemes to address the risks posed by increasing penetration of Distributed Energy Resources (DER).

Due to the network topologies, load densities, sub-transmission protection systems and historical programs of work the tactical augmentation of the Energex network has not been identified as having the same exposure for protection systems being affected by DER. Therefore, the problems and solutions identified in this report are only intended for the Ergon Energy network.

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.

1.2 Scope of document

This document lays out the requirement for implementing protection schemes which can reliably detect and de-energise faults which occur on systems with a high penetration of DER.

1.3 Identified Need

Energy Queensland 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), customer reliability and preparing the network for the ongoing adoption of new technology by customers (e.g. solar PV). In this business case network safety risk mitigation is a strong driver, due to the need to address reverse flow issues across the Ergon Energy network arising from the increased uptake of DER by customers.

Ergon Energy's existing network and protection systems were designed to support radial network topologies and assumed a one-way power flow from Ergon Energy to the customer.

The modern network is evolving, and customers can connect DER (most commonly solar generation systems) at the residence. Penetration is increasing - there are 645 distribution feeders on Ergon Energy's network which are experiencing reverse power flows due to high penetration of DER.

The risk associated with reverse power flow is that network conditions may exist where islanded networks can be created under certain operating arrangements. Islanded arrangements create the following risks:

- If there is no protection inter-tripping scheme, due to incapable relays or lack of protection communications, earth faults on the network providing electrical supply to a substation may be cleared at the traditional supply end only. The complex combination of inertia from customers loads, energy storage and voltage regulation equipment has the ability to defeat the anti-islanding protection schemes employed at the DER locations. The potential to defeat anti-islanding protections removes the certainty of deenergising the network for some fault types. Under this scenario an energised power line may remain on the ground undetected, which is an unsafe situation and does not comply with NER requirements for fault detection and isolation. This has already occurred at Barcaldine where the generators on the 22kV network back-energised a fault on the 66kV network. Uncleared faults breach the NER and are a safety risk to staff and the public.

- Faults on the sub-transmission network, even those detected and cleared by protection, can cause Under Frequency Load Shedding (UFLS) to operate incorrectly on the distribution network if there is high DER penetration. This has already occurred at East Warwick Zone Substation (ZS) in October 2016 where five distribution feeders were tripped during the dead time of an upstream sub-transmission feeder trip and re-close. In this case the distribution network did not shutdown as soon as the sub-transmission circuit was disconnected. The generation and load combination connected at 11kV decelerated (the frequency was decreasing), at the same time the voltage was decaying. In this case the voltage remained at a sufficient magnitude to not block the under-frequency protection. Upon automatic restoration of the sub-transmission feeder the customers remained without power until it was diagnosed and manually restored.

The program of works identified in this proposal is required to ensure Energy Queensland can meet current and future business requirements and will support meeting our obligations for legislated compliance, by ensuring ongoing and reliable operation of protection schemes. These are described in the following sections. This proposal aligns with the CAPEX objectives, criteria and factors from the National Electricity Rules as detailed in Appendix C.

1.4 Energy Queensland Strategic Alignment

Table 1 details how DER protection schemes 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 D.

Table 1: Asset Function and Strategic Alignment

Objectives	Relationship of Initiative to Objectives
Ensure network safety for staff contractors and the community	Ensure that systems with high penetration of DER cannot maintain a network energised in a faulted condition, with a power-line on the ground.
Meet customer and stakeholder expectations	Reliably remove unsafe operating scenarios from the network, protecting customer and stakeholder equipment. Improve capability of the network to sustain increased DER penetration.
Manage risk, performance standards and asset investments to deliver balanced commercial outcomes	Appropriately managing the impacts of high DER penetration allows more customers to connect to the grid. The alternative limited first-come first-served scheme is not a balanced outcome. High DER penetration can assist in supporting the network during peak load times, which can help EQL meet the required performance standards of the network. To prevent high DER negatively impacting performance, appropriate protection schemes are required
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.

Objectives	Relationship of Initiative to Objectives
Modernise the network and facilitate access to innovative energy technologies	The modern network will incorporate increasing levels of DER therefore protection systems must be updated to address the additional risks which are identified as a consequence.

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 2013**	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]	Improved distribution protection schemes will help reliably detect and clear faults where there is high DER penetration, meeting EQL's obligation to ensure works are electrically safe and helps ensure the electrical safety of EQL staff and the public. Incorporating additional or upgraded protection schemes will help prevent or reduce incorrect UFLS operation, increasing the

[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
		quality and reliability of supply to customers.
Distribution Authority for Ergon Energy or 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 increase the risk of unnecessary UFLS trips or uncleared faults, where there is high DER penetration. This impacts 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 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	S5.1.9(c) requires that a fault of any type anywhere on the distribution system is automatically disconnected. Current schemes with high DER penetration may not automatically isolate some faults. This is addressed by this proposal.

1.7 Limitation of existing assets

Energy Queensland has a generator network connection standard that encourages inverter based embedded generation with ratings up to 1.5MW to be connected to the distribution network. Ratings up to 1.5MW require no special protection schemes to be paid for by the customer, unlike larger installations which would be required to address consequential protection limitations. The impacts of higher (and growing) penetration are described below:

- On 232 zone substations and 645 distribution feeders, DER generation frequently exceeds load consumption on the network, causing reverse power flows. Currently 40 substations see reverse power flows at the sub-transmission level.
- It is forecast that additional sub-transmission sites will transition from being loads to generation sources due to the natural uptake of DER at the residential and commercial level during the next regulatory period.

Historically, protection schemes have been designed to detect and clear faults where all fault energy is supplied from centralised sources with relatively high fault levels, i.e. from EQL to the customer. Reliable detection and isolation of reverse-energised faults is not guaranteed, which can create unsafe situations. In particular an earth fault on the sub-transmission network may remain energised by DERs on the distribution network if there is no inter-tripping in place to ensure that all circuit breakers are opened. These situations result as a failure of the embedded generation failing to disconnect and becomes more likely as the size of the islanded network increases.

Where a fault remains reverse-energised, an island is likely to occur which may not maintain adequate voltage or frequency. S5.1.9(c) of the NER requires that any faults anywhere on the transmission or distribution system be automatically disconnected.

UFLS schemes need to be set such that defined amounts of load are reliably reduced rapidly. During high DER generation, distribution feeders will have reduced net load or will reverse-energise the zone substation, potentially changing the zone substation to a net generator. This can make it difficult to plan which feeders will deliver adequate load shedding when included in a UFLS scheme. Tripping feeders with reverse flows may exacerbate the under-frequency event rather than helping to correct it, resulting in cascading UFLS operation which negatively impacts reliability for customers and can contribute to network instability. EQL's existing under-frequency load shedding schemes are not designed to account for significant generation in the distribution network.

2 Counterfactual Analysis

2.1 Purpose of asset

Energy Queensland's protection assets are vital to ensure the safe, reliable operation of the electricity grid in Queensland. Comprehensive protection schemes are required to ensure faults are automatically cleared with minimal fault duration and minimal network isolation. In a network with high DER penetration, protection must be able to clear faults that are energised by both the grid and DER. Protection must not trip when there is no fault present, or when another device could clear the fault with less network isolated.

2.2 Business-as-usual service costs

There is no acceptable 'Do Nothing' state in this study. The risks arising from no augmentation are unacceptable as detailed below.

2.3 Key assumptions

The following were assumed during the analysis for this business case:

- DER uptake will continue at the current or greater rate over the regulatory period.
- Faults on the Sub-transmission networks are back-energised by DERs due to inadequate protection. This has already occurred at Barcaldine where the generators on the 22kV network back-energised a fault on the 66kV network, where the 66kV had successfully tripped. Uncleared faults breach the NER and are a safety risk to staff and the public.
- Increasing risk of failure of UFLS to correctly operate due to DER. Incorrect UFLS operation due to embedded generation has already occurred at East Warwick ZS where five distribution feeders were unnecessarily de-energised for 6 hours.
    - Assuming each feeder supplied 5MW of load, with 50% diversity an estimated 80MWh was lost. The current aggregate weighted average Value of Customer Reliability (VCR) in Queensland is $39.71 per kWh, resulting in an estimated VCR of $2.224M to $4.130M for this one event, allowing for +-30% accuracy in the VCR value.
    - As this is a recent issue there are not enough occurrences to estimate a per 10-year event frequency. It has been assumed that this event may occur once per year.

2.4 Risk assessment

The following risks have been identified as a result of not addressing the identified limitations. These risks are unacceptable and result in safety issues and compliance failures. This risk assessment is in accordance with the EQL Network Risk Framework and the Risk Tolerability table from the framework is shown in Appendix E.

Table 3: Counterfactual risk assessment

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Failure of protection to clear an earth fault results in inadvertent contact with an energised source and **a single fatality**.	Safety	5 *(Single fatality)*	3 *(Unlikely)*	**15** ***(Moderate)***	2025

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Spurious under-frequency trips impact customer reliability and satisfaction.	Customer Impact	3 *(Customer impact 5000 customer > 1min)*	3 *(Unlikely)*	**9** ***(Moderate)***	2030
Unintentional islanding results in voltage and/or frequency outside of prescribed limits, negatively impacting quality of supply resulting in **a breach of the QLD Electrical Safety Regulation 2006 s11**.	Legislated	4 *(Energex/Ergon identified issue requiring regulator to be notified. Improvement notice issued)*	2 *(Very unlikely)*	**8** ***(Low Risk)***	2019

2.5 Retirement or de-rating decision

Reducing or restricting the amount of generation that can be installed in the distribution network could lower or prevent the risk of DERs causing reverse power flow or islanded scenarios. This would allow EQL to continue with historical protection design. This is an unacceptable solution as modern customers have an expectation of being able to connect DER to the network and would not accept being limited to a first come first serve basis.

3 Options Analysis

3.1 Options considered but rejected

Table 4 lists the options considered and rejected in this assessment, and their reasons for rejection.

Table 4: Options considered but rejected

Option	Reasons for rejection
Limit penetration of DER to a level that allows the existing protection schemes to continue to properly operate in a manner aligning with historical requirements. This restriction would be to a level that prevents or severely reduces the frequency of reverse power flow scenarios.	• Many feeders have already exceeded this level resulting in reverse power flows. • Limiting the amount of DER is expected to result in potential electricity market impacts due to blocking a potential source of cheaper generation • Reputational damage to EQL resulting from restricting DER uptake.
Implement protection augmentations as required to address the risks of high DER penetration but require 0-1.5MW customers to pay for the augmentations, similar to current requirements for large embedded generators.	• Network augmentations are typically prohibitively expensive to small customers and would prevent them from connecting • Not practical to administer equitably
Ensure customer inverters can be switched off remotely by EQL.	• Already significant penetration and not all customers inverters are likely to be compatible with this requirement.
Counterfactual “Do nothing”	• Results in unacceptable safety risks of uncleared faults • Results in unacceptable non-compliance of the NER and the QLD Electrical Safety Regulation 2006

3.2 Identified options

3.2.1 Network options

There are various technical options available to address the identified risks caused by high DER penetration on the distribution network and have been detailed below. The identified options do not necessarily all need to be applied at each site of concern. The most economic option to address, based on existing network configuration and equipment, will be selected following a more in-depth business case for each site.

Protection schemes required to address the risks outlined will be one or a combination of the below.

Sub-transmission fault back-energisation due to DER

Options to address include:

Option 1 – Proposed

- Installation of Neutral Voltage Displacement (NVD) protection at substations without sufficient existing communications to allow for inter-tripping between substations
- At substations with sufficient communications, install relays or make setting changes necessary to provide inter-tripping to ensure that a fault on the sub-transmission network is not able to be back-fed from the distribution network.
- 50% of the 40 substations where there is an identified risk of back-fed faults have existing communications equipment.

Option 2

Install Neutral voltage displacement (NVD) protection at all 40 substations which can detect when the network is energised with an earth fault present. A Voltage Transformer (VT) may need to be installed to allow this.

Mal-operation or non-operation of UFLS protection

Options to address include:

Option 1 – Proposed:

- Implement changes to 11kV UFLS to improve operation with high penetration of DER at a pilot site during the 2020-25 regulatory period. This may include a communications system or implementation of dynamic arming, to be determined as part of the pilot project. The changes would be expected to deliver high speed recognition of islanded networks and manage the resulting underfrequency event, either through implementation of load restoration schemes, or inhibiting underfrequency protection.
- Using the outcomes of the pilot project, roll-out upgrades to UFLS at substations with high DER penetration during the next regulatory period.

Option 2:

- Implement changes to 11kV UFLS to improve operation with high penetration of DER at all sites with reverse power flows during the 2020-25 regulatory period.

3.2.2 Non-network options

There are no feasible non-network options available to address the risks caused by high DER penetration in the network.

3.3 Economic analysis of identified options

3.3.1 Cost versus benefit assessment of each option

The historical spend on protection augmentation required due to DER penetration over the previous regulatory period was $8.5M. Due to the difficulty of determining the extent of required augmentations at sites with reverse power flow without completing a detailed business case, the previous spend has been used as a base estimate.

Capital Costs

Sub-transmission fault back-energisation due to DER

- **Option 1** - Upgrade of protection schemes at the 40 locations with sub-transmission reverse-flows is estimated to cost an average of $125,000 per location, at a total cost of $5M, given that 50% of sites already have sufficient protection communications to allow for inter-tripping schemes. NVD protection will be installed at the remaining 50% of sites.
- **Option 2** - Upgrade of protection schemes at the 40 locations with sub-transmission reverse-flows is estimated to cost $250,000 per location, at a total cost of $10M NVD protection and VTs will be installed at all 40 sites.

Mal-operation or non-operation of UFLS protection

- **Option 1** - Pilot site implementation of UFLS upgrades during the 2020-25 regulatory period is estimated to cost $1M.
- **Option 2** - Implementing UFLS upgrades at all sites with high DER penetration is estimated to cost $86,000 per site. 232 zone substations currently experience reverse power flows and are at risk of reverse flows resulting in unnecessary UFLS operation, with an estimated cost of $20M to rectify.

Table 5Table 5 and Table 6 presents a summary of cashflows for each option.

Table 5: Annual cashflows back-fed earth fault protection

Activity	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Option 1						
Inter-tripping and NVD protection	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	**$5,000,000**
TOTAL	**$1,000,000**	**$1,000,000**	**$1,000,000**	**$1,000,000**	**$1,000,000**	**$5,000,000**
Option 2						
NVD protection	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	**$10,000,000**
TOTAL	**$2,000,000**	**$2,000,000**	**$2,000,000**	**$2,000,000**	**$2,000,000**	**$10,000,000**

Table 6: Annual cashflows UFLS upgrades

Activity	2020/21	2021/22	2022/23	2023/24	2024/25	Total
Option 1						
UFLS pilot project.	$200,000	$200,000	$200,000	$200,000	$200,000	**$1,000,000**
TOTAL	**$200,000**	**$200,000**	**$200,000**	**$200,000**	**$200,000**	**$1,000,000**
Option 2						
UFLS upgrades at all substations with reverse power flows.	$3,990,400	$3,990,400	$3,990,400	$3,990,400	$3,990,400	**$19,952,000**
TOTAL	**$3,990,400**	**$3,990,400**	**$3,990,400**	**$3,990,400**	**$3,990,400**	**$19,952,000**

Results

Table 7 outlines the Net Present Value (NPV) and direct cost of Options 1 and 2, with NPV calculated by discounting cashflows over a 15-year study period at the Regulated Real Pre-Tax Weighted Average Cost of Capital (WACC) rate of 2.62%.

Table 7: Net present value of sub-transmission back-fed earth faults

Option	Option Description	NPV	Direct Cost ($18/19 Dollars)
1	Installation of inter-tripping at 20 sites and NVD protection at 20 sites.	-$3.95M	$5M
2	Installation of NVD protection at 40 sites.	-$7.9M	$10M

Table 8: Net present value of UFLS upgrades

Option	Option Description	NPV	Direct Cost ($18/19 Dollars)
1	UFLS pilot project.	-$0.79M	$1M
2	UFLS upgrades at all substations with reverse power flows.	-$15.7M	$19.9M

3.4 Scenario Analysis

3.4.1 Sensitivities

The requirement of the augmentation discussed above is sensitive to the DER uptake rate. If the rate of penetration increases significantly then the timeframe available for completing works will shorten and increase the number of locations likely to require works. This could result in an increase in unnecessary protection trips as well as an increase in Dangerous Electrical Events (DEEs) where faults are not properly or promptly cleared and staff or the public are placed at risk. This could also potentially result in extended outages for customers.

3.4.2 Value of regret analysis

In terms of selecting a decision pathway of 'least regret', Option 1 for both assessed requirements present an economically efficient, balanced approach to investment by targeting works based on cost and reliability assessments and reducing risk to the greatest extend without bringing forward unnecessary expenditure.

The key regrets in this business case are:

- Uncleared earth fault on the sub-transmission network being energised by DERs installed on the distribution network. Uncleared faults are unacceptable under the NER and pose a significant safety risk.
- Incorrect operation of distribution protection or UFLS schemes resulting in significant reliability of supply impact to customers.

Load growth in the network, or lack of it, has an impact on this project. Increased load growth may offset the penetration of DER, provided it grows at a rate greater than DER penetration. This is not forecast and has not factored into consideration. Lack of load growth combined with increasing DER penetration results in an effective decrease in load during certain times, to the extent of causing reverse flows on the network. Over time, this is likely to increase the number of substations that require protection upgrades to accommodate reverse flows, as well as the number of UFLS-enabled locations that need changes based on the outcomes of the proposed pilot program to continue to operate effectively.

The proposed options will reduce the identified key risks and provide a pathway to eliminating them in the future.

3.5 Qualitative comparison of identified options

3.5.1 Advantages and disadvantages of each option

Table 10 details the advantages and disadvantages of each option considered.

Table 9: Advantages and disadvantages of considered options for sub-transmission back-fed faults

Option	Advantages	Disadvantages
Option 1: Installation of inter-tripping at 20 sites and NVD protection at 20 sites.	• Reduces risk of faults damaging equipment • Reduces risk of faults remaining energised by DERs and endangering staff or the public • Allows higher penetration of DERs improving customer experience	• More sites than expected may lack sufficient protection communications to allow for an inter-tripping scheme. This would result in a higher cost than expected and not all sites would be able to be upgraded during this regulatory period, resulting in higher risk.
Option 2: Installation of NVD protection at 40 sites.	• Reduces risk of faults damaging equipment • Reduces risk of faults remaining energised by DERs and endangering staff or the public • Allows higher penetration of DERs improving customer experience	• High cost of protection upgrades • Significant resource investment required (staff and time)
Do Nothing	• Reduce expenditure on protection augmentation	• Increased risk of uncleared faults – high safety risk • Increased risk of quality of supply issues due to islanded networks

Table 10: Advantages and disadvantages of considered options for UFLS upgrades

Option	Advantages	Disadvantages
Option 1: UFLS pilot project	• Allows higher penetration of DERs improving customer experience • Provides a pathway to reduces or prevents incorrect UFLS operation increasing reliability of supply at a more economical cost during the next regulatory period	• Delays the implementation of any identified solution.
Option 2: UFLS upgrades at all substations with reverse power flows.	• Allows higher penetration of DERs improving customer experience • Reduces or prevents incorrect UFLS operation increasing reliability of supply	• High cost of protection upgrades • Significant resource investment required (staff and time) • Increased exposure to risk of cost and scope creep due to the uncertainty of viable solution to UFLS issues
Do Nothing	• Reduce expenditure on protection augmentation	• Increased risk of incorrect UFLS operation potentially causing system instability and unnecessary interruptions to supply

3.5.2 Alignment with network development plan

The Distribution Annual Planning Report (DAPR) 2018-2023 outlines the plan to ensure the adaptability of the distribution system to new technologies and to support customer choice through the provision of technology neutrality and reducing barriers to access the distribution network. Augmenting the protection system to be capable of supporting a wide range of DER penetration is necessary to comply with this strategy.

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.

Additionally, installing or augmenting protection schemes to allow increasing penetration of DER helps EQL contribute to the future distributed, sustainable electricity network. The Future Grid Roadmap outlines the requirement to ensure the adaptability of the distribution system to new technologies. Augmenting the protection system to be capable of supporting a wide range of DER penetration is necessary to comply with this strategy.

3.5.4 Risk Assessment Following Implementation of Proposed Option

The risk of spurious under-frequency trips impact customer reliability and satisfaction will only be mitigated across the network during the next regulatory period, with existing risk to remain during the 2020-25 regulatory period.

Table 11: Risk assessment showing risks mitigated following Implementation

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Failure of protection to clear an earth fault results in inadvertent contact with 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)***	2025
Spurious under-frequency trips **impact customer reliability and satisfaction**.	Customer Impact	*(Original)* *4* *(Customer impact >$1M)* (Mitigated) 4 *(As above)*	 *3* *(Unlikely)* 3 *(Unlikely)*	 ***12*** ***(Moderate)*** **4** ***(Very Low)***	2030
Unintentional islanding results in voltage and/or frequency outside of prescribed limits, negatively impacting quality of supply resulting in **a breach of the QLD Electrical Safety Regulation 2006 s11**.	Legislated	*(Original)* *4* *(Energex/Ergon identified issue requiring regulator to be notified. Improvement notice issued)*	 *2* *(Very unlikely)*	 ***8*** ***(Low Risk)***	2019

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
		(Mitigated)			
		4 *(As above)*	1 *(Almost no likelihood)*	**4** ***(Very Low)***	

4 Recommendation

4.1 Preferred option

For both identified drivers, Option 1 is the preferred option. For sub-transmission back-fed earth faults, the use of dedicated protection schemes in combination with protection communications provides a method of mitigating the emerging risks.

The implementation of a pilot UFLS scheme will allow all emerging issues to be addressed and allow for specific remediation programs to be implemented.

4.2 Scope of preferred option

Individual sites will have varying scope dependent on system configuration and existing equipment available. Substations and feeders with reverse power flow will be investigated and appropriate protection augmentations will be installed to rectify the following issues as required on a site-by-site basis.

Where existing protection communications between substations are available, an inter-tripping scheme will be implemented in existing relays if they are capable, or in new relays if not. At all other locations NVD protection will be installed.

At a pilot site with UFLS and reverse flows, implement changes to 11kV UFLS to improve operation with high penetration of DER. This may include a communications system or implementation of dynamic arming, with the most effective, economical option for network-wide roll-out to be determined as part of the pilot project.

The overall estimated CAPEX cost for the proposed options is $6M (real $2018/19 dollars).

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, *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
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
DEE	Dangerous Electrical Event
DER	Distributed Energy Resource
DNSP	Distribution Network Service Provider
EQL	Energy Queensland Ltd
IT	Information Technology
KRA	Key Result Areas
kV	Kilovolt
MSS	Minimum Service Standard
MW	Megawatt
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
NPV	Net Present Value
NVD	Neutral Voltage Displacement

Abbreviation or acronym	Definition
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
UFLS	Under Frequency Load Shedding
VCR	Value of Customer Reliability
VT	Voltage Transformer
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 12: 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 13: 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)	$6.00
Business Case Value	
(M$2020)	$6.21