Business Case
Substation Transformers

Executive Summary

Power transformers change the voltage level between different sections of an electricity network. This enables electricity transportation infrastructure to be significantly more cost-effective, by reducing the power losses experienced between generators and consumers, while providing power at the appropriate voltage for end-users.

Substation transformers are considered critical assets, as they are high value and can require significant lead times to repair or replace in the event of failure. This business case considers the risk of simultaneous failure for two transformers at substations with multiple transformers, and single transformer failure at substations with only one transformer. These type of failure events have the potential to result in substantial and extended customer load interruption, as well as negative environmental and safety outcomes. There is also not an alternative means of providing the power transformation services the assets supply, which are necessary for the cost-effective operation of the sub-transmission network.

Two options for managing the condition of substation power transformers were evaluated in this business case:

Option 1 – A counterfactual, 'run-to-failure' option under which transformers are left to fail in-service and then replaced reactively.

Option 2 – A risk-based replacement program, under which ageing and poor condition assets are identified for replacement.

Ergon Energy aims to minimise expenditure in order to keep pressure off 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 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 reliability are strong drivers, based on the need to manage the risk of failure in-service of ageing and poor condition power transformers.

Detailed quantitative risk assessments were carried out for each of the proposed transformer replacements under Option 2 with reference to the counterfactual, 'run-to-failure' case presented under Option 1. The proposed transformer replacements were based on asset condition, as per the Energy Queensland Asset Management Plan – Substation Transformers.

The analysis indicated that for the proposed sites, the benefits realised in terms of risk reduction from replacing the assets before failure more than offset the cost of the replacement program outlined in Option 2. The Net Present Value (NPV) of Option 2 is $46.1M, indicating it delivers significant risk reduction benefits.

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
$36.7M	N/A	$36.7M

Contents

1 Introduction

Substation power transformers are considered critical assets within the network. They enable the cost-effective transformation of electricity by facilitating changes in voltage level, and many serve as an earth reference point for load side circuits which is a critical network protection feature.

Ergon Energy manages these assets on a condition and risk basis, proactively replacing those assets which are no longer safe to leave in operation based on expected failure rates and associated consequences of failure.

1.1 Purpose of document

This document recommends the optimal capital investment necessary for the Substation Transformers replacement program.

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 Ergon Energy 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 (EQL) investment governance processes. The costs presented are in $2018/19 direct dollars.

1.2 Scope of document

This document outlines the need and options available for managing the replacement of Substation Transformers within the Ergon Energy network. It is related only to the class of assets known as substation power transformers.

This document should be considered in conjunction with the Energy Queensland (EQL) Asset Management Plan (AMP) – Substation Transformers.

1.3 Identified Need

Ergon Energy aims to minimise expenditure in order to keep pressure off 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 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 reliability are strong drivers, based on the need to manage the risk of failure in-service of ageing and poor condition power transformers. This replacement program is a continuation of an existing condition-based replacement strategy for substation transformers.

Substation transformers are considered critical in nature as they are high value assets which can require significant lead time to repair or replace. When two transformers fail simultaneously at a multi-transformer substation, or when the sole transformer at a substation fails, there is typically not an immediate alternative means of providing the power transformation services they supply. The risk of unserved load is generally more significant for substations with larger loads (~20 MVA) but may still be material for smaller substations depending on location (e.g. rural) and the configuration of the network. As such, failure events have the potential to result in substantial and extended customer load interruption, as well as negative safety outcomes.

A critical modelling assumption used in the analysis associated with this business case is the failure rate of the individual transformers. The modelling has used a prediction of individual transformer failures based on age, however it should be noted that this is a conservative assumption in that consequent failures of a second transformer at the same site sometimes occur. The failure rate for second transformers is believed to be higher due to factors including:

- The mechanical forces on the parallel transformer can cause a failure due to the passage of fault current when the first transformer fails; and
- The increased loading on the second transformer will cause higher stresses on an already significantly aged unit.

The critical nature of these assets combined with their relatively low population makes it prudent and cost effective to manage them on an individual basis, and to replace them when they are approaching end of life but prior to failure, to avoid catastrophic failure and the associated load interruption and safety consequences. The proposed transformer replacements related to assets that are in poor condition and approaching the end of their service life. This is in alignment with the EQL AMP – Substation Transformers.

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 the replacement program for Substation Transformers 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	The in-service failure of substation transformers can lead to dangerous outcomes (e.g., device fire or explosion). These outcomes can endanger substation personnel and to a lesser extent the public. Diligent and consistent maintenance and replacement operations support substation transformer performance and therefore promote safety for stakeholders.
Meet customer and stakeholder expectations	Failure of substation transformers can lead to extended load interruptions, due to the significant lead time associated with repairing and replacing failed units. Maintaining the serviceability of the substation transformer asset base therefore supports the delivery of standard quality electrical energy services to customers.
Manage risk, performance standards and asset investments to deliver balanced commercial outcomes	Failure of a substation transformer can result in increased EQL personnel safety risk and disruption of the electricity network. Condition-based replacement manages this risk without unnecessarily bringing forward capital expenditure and introducing short-term price pressure on customers.
Develop Asset Management capability & align practices to the global standard (ISO55000)	This replacement program is consistent with ISO55000 objectives and drives asset management capability by promoting a continuous improvement environment.
Modernise the network and facilitate access to innovative energy technologies	This program promotes the replacement of substation transformers at the end of their economic life as necessary to suit modern standards and 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 1.

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 outlines the compliance obligations relevant to this proposal.

Table 2: Compliance obligations related to this replacement program

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]	This replacement program addresses the need to replace substation transformers in the network which are in poor condition and therefore at greater risk of failure. When these assets fail, they pose a safety risk for staff, the public and other assets in the same substation directly through fire or explosive failure.
Distribution Authority for Ergon Energy issued under section 195 of *Electricity Act 1994* (Queensland)	Under its Distribution Authority: • The distribution entity must plan and develop its supply network in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services. • The distribution entity will ensure, to the extent reasonably practicable, that it 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)	The significant lead time associated with repairing or replacing a failed transformer means that customers could face an extended interruption of their supply in the event of failure. This replacement program is necessary to meet safety net targets and MSS, by ensuring the reliable operation of the network.
Environmental Protection Act 1994	Section 319 of the Environmental Protection Act 1994 contains a general environmental duty: A person must not carry out any activity that causes, or is likely to cause, environmental harm unless the person takes all reasonable and practicable measures to prevent or minimise the harm.	Substation power transformers, regulators, and reactors carry substantial volumes of mineral oil, typically between 5,000 and 10,000 litres. A significant discharge of oil from a leaking transformer at a substation may create material environmental issues that constitute an offence under the Act.

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

1.7 Limitation of existing assets

The replacement of substation transformers is required due to the degradation of these assets over the course of their service life, as the materials and components used in their construction deteriorate. If left to degrade, substation transformers will eventually fail in-service, potentially leading to an extended interruption of customer load and potentially leading to catastrophic failure (with associated negative safety and environmental consequences).

In general, the degradation of substation transformers is a result of the expected electrical and mechanical ageing incurred during the regular operation of the transformers over a long period. However, some other factors also contribute to the need for replacement.

Environment

The degradation process can be accelerated by environmental factors. Transformers situated in outdoor, corrosive or coastal environments will experience accelerated deterioration of components such as their tank, bushings, gaskets and instrumentation.

Moisture ingress is another known issue related to the transformers' environment. This phenomenon leads to the degradation of paper within the transformer insulation, which can ultimately cause insulation failure.

Loading

Excessive loading above the cyclic rating of a transformer can lead to the rapid degradation of its paper insulation, due to the heating of its winding. This also accelerates the asset ageing process, reducing its useful life, and can cause internal faults which lead to catastrophic failure.

Obsolescence

Apart from degradation, asset obsolescence can also drive the need for replacement. If it is no longer possible to source components required for maintain or repairing the asset, particularly any of the moving components or the bushings, it will not be possible to return it to service when it fails. Early replacement of the asset may therefore be required to manage the risk generated by a lack of spare parts.

2 Counterfactual Analysis

Under a ‘run-to-failure’ counterfactual approach, the identified substation transformers would be permitted to fail in-service, rather than being replaced proactively based on condition, age and risk factors. The key issue associated with this approach is that it would increase the risk of significant and extended load interruptions for customers when the assets fail in-service.

A further factor is that in many cases, multiple power transformers at a site were installed at the same time and are now in a similarly deteriorated condition. A known phenomenon is the failure of a second power transformer when the first transformer fails in service. This arises for two reasons:

(a) The “through-fault” when the first transformer fails produces significant electrical and mechanical forces in the adjacent transformer, and result in sympathetic failure, especially when both transformers are in poor condition; and

(b) In the event that the second transformer does not fail, it will bear substantially increased demand, often at or above its rated capacity. This high demand on a transformer can lead to a failure a short time after the initial transformer failure.

Such dual failure events have occurred in the past and while the higher failure rates for second transformers have not been modelled in this analysis, it is a further risk and rationale for condition-based replacement rather than allowing both transformers to run to fail. This means that the modelling provides a conservatively low estimate of the risks of multiple failures.

2.1 Purpose of asset

Power transformers change the voltage level between different sections of an electricity network. This enables electricity transportation infrastructure to be significantly more cost-effective, by reducing the power losses experienced between generators and consumers, while providing power at the appropriate voltage for end-users.

2.2 Business-as-usual service costs

Allowing the identified poor condition and aged transformers to remain in service will likely lead to higher operational costs, due to the increased maintenance required to keep these assets in service as their condition deteriorates. Further, their eventual failure in service will increase the cost of replacement due to the assets needing to be replaced under emergency, rather than planned, circumstances.

2.3 Key assumptions

Under a ‘run-to-failure’ counterfactual approach, the increased rate of failure-in service for substation power transformers will prevent the safe and efficient operation of the network. Appendix F details the input assumptions associated with the quantification of risk of the condition-related failure for the set of Ergon Energy substation transformers considered in this business cases.

Qualitatively, the failure in-service of substation transformers has several potential consequences:

- **Extended interruption of customer load:** Substation power transformers perform a critical role in the network in terms of supply, transforming high voltage power into a low voltage, usable form for customer. Their failure in-service can lead to lengthy disruptions to supply for customers, as there is typically a long lead-time associated with asset repair or replacement, and there is no alternative means of supplying low voltage power once a unit fails.
- **Catastrophic failure of an asset:** Failure events have the potential to result in negative safety consequences. These assets can explode when they fail, with fragments from their

external insulation posing a risk to substation maintenance personnel and other substation equipment in the vicinity.

- **Loss of access to substation sites:** When substation power transformers are found to be in poor condition and therefore at an elevated risk of experiencing a catastrophic failure, a Network Access Restriction (NAR) can be imposed on the substation for safety reasons. This restricts both site access and the scope of work that can be performed on site, adding cost to routine works, extending preventative and routine maintenance periods on nearby assets, and inhibiting operation of the network.
- **Environmental Harm:** In some of its substations, Ergon does not have adequate oil containment / bunding facilities. While this situation is being progressively improved, many aged sites are inadequate and hence pose a risk should one or more transformer fail. Oil leakage from a faulted transformer is a relatively common occurrence with the forces of the fault creating additional pressure inside the transformer tank. Leakage of large volumes of oil represents a significant risk of environmental harm. Due to the potential environmental harm, these normal/routine leaks must be repaired at un-bunded sites, which is an additional expense that must be incurred by Ergon Energy.

2.4 Risk assessment

A detailed risk quantification analysis was completed for each transformer replacement site. A model was used to forecast power transformer failure and quantify all known risks including customer outages, emergency replacement costs, safety risks and environmental harm. The quantified risks were compared to the replacement cost at each site and a NPV was determined. Further details of the risk quantification approach are contained in Appendix F.

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
<u>Interruption of customer load</u> – A substation transformer fails in-service, leaving customer load unserved while load is transferred, back-up generation mobilised, and capacity is eventually restored at the affected substation site.	Customer	3 *Time to restore service exceeds 12 hours.*	3 *(Unlikely)*	**9** ***(Low Risk)***	2025
<u>Increased load at other sites</u> – Transfer of load to other substations in response to a transformer failure will lead to an abnormal network configuration, leading to higher than usual load at other sites. This may accelerate the degradation of other transformer assets.	Business	3 *(Abnormal network configuration)*	3 *(Unlikely)*	**9** ***(Low Risk)***	2025
<u>Catastrophic failure</u> – Multiple serious injuries occur because staff members or members of the public are in the vicinity when a transformer fails catastrophically.	Safety	4 *(Multiple serious injuries)*	3 *(Unlikely)*	**12** ***(Moderate Risk)***	2025

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Oil leakage – Some substations have inadequate bunding to prevent an oil spill and soil contamination in the event a transformer fails in-service.	Environment	5 *(Long term contamination of the environment)*	3 *(Unlikely)*	**15** ***(Moderate Risk)***	2025

2.5 Retirement or de-rating decision

These assets are critical in nature, and there is no alternative asset which could provide the same service within substations (i.e. voltage transformation) when simultaneous unit failure occurs (or sole unit failure occurs at single transformer locations). It is therefore not possible to consider retiring these assets from service. When a replacement occurs, it is usual that the exiting asset is retired, and the replacement unit is established with optimal sizing based on demand forecasts, scale economy and optimal utilisation.

3 Options Analysis

This section outlines the options considered to manage the proactive replacement of substation power transformers in substations in Ergon Energy's network, required due to normal degradation over the course of their service life.

3.1 Options considered but rejected

None of the identified options for this business case have been rejected.

3.2 Identified options

Three network options have been considered to proactively manage the condition of substation power transformers in the Ergon Energy Network:

- Option 1 – 'Run-to-Failure' (Counterfactual – See Section 2)
- Option 2 – Risk Based Replacement (Preferred)

3.2.1 Network options

Option 1 – 'Run-to-failure' (Counterfactual)

See Section 2 above. Assets left in service until they ultimately fail, and then replacement works are carried out on a reactive basis.

Option 2 – Risk Based Replacement (Recommended)

Under this option, the failure consequence risks (safety, customer reliability, environmental and business) for each individual substation transformer are assessed and used to form the basis of replacement. Ergon Energy would consider assets as candidates for replacement on the basis of a quantitative risk assessment for each substation site, considering the cost of replacement against the net benefit (measured as a reduction in quantified risk).

3.2.2 Non-network options

There were no non-network options identified at this stage of the planning process. However, the cost of replacement at a large proportion of the substation is large enough to require RIT-D approval. Non-network solutions will be explored during the RIT-D process as per the guidelines.

3.3 Economic analysis of identified options

3.3.1 Cost versus benefit assessment of each option

The Net Present Value (NPV) of each option has been determined by considering costs and benefits over the program lifetime from FY2020/21 to FY2049/50, using EQL's standard NPV analysis tool. The tool incorporates any residual value for assets at the end of the program lifetime into the NPV analysis.

Risk Monetisation

The risk of asset failure has been assessed along with the potential consequences of failure for both Option 1 and Option 2, to produce a monetised total risk value for each year across the period for both options. The costs of consequence and probabilities used to build up the monetised total risk value are described in Appendix G.

Benefits of Replacement

The benefits associated with replacing transformers at each of the proposed substation sites has been evaluated by comparing the total monetised risk under Option 1 ('Run-to-Failure) and the total monetised risk under Option 2 (wherein assets are replaced prior to failure).

Cost of Replacement

Transformer unit replacement costs have been developed based on historical replacement cost data for Ergon Energy and assumed to be $1.18 million per transformer.

Results

Table 4 below summarised the results of the net present value analysis for Option 2, assessed against Option 1 (the counterfactual). The Regulated Real Pre-Tax Weighted Average Cost of Capital (WACC) rate of 2.62% has been applied as the discount rate for this analysis (as per EQL's Standard NPV Tool).

A positive NPV indicates that the risk reduction benefits realised through transformer replacement at the site outweigh the capital costs of replacing the asset. The total NPV delivered by the replacement program is $46.3 million.

Table 4: NPV of replacement for Option 2 relative to Option 1

Substation Site	PV CAPEX	PV Benefits	NPV
Barcaldine	$2,252,745	$10,207,919	$7,955,174
Barratta	$1,126,373	$4,554,260	$3,427,888
Cape River	$1,069,592	$1,944,304	$874,712
Crows Nest	$1,015,673	$4,343,572	$3,327,898
Chinchilla	$1,015,673	$3,003,778	$1,988,105
Disraeli	$989,742	$1,772,487	$782,745
East Bundaberg	$1,126,373	$2,809,625	$1,683,253
Hermit Park	$2,139,184	$7,225,692	$5,086,508
Jandowae	$1,126,373	$2,772,198	$1,645,825

Substation Site	PV CAPEX	PV Benefits	NPV
Jarvisfield	$2,139,184	$3,527,657	$1,388,474
Kilkivan	$2,084,568	$3,753,482	$1,668,914
Mitchell	$1,155,884	$5,105,324	$3,949,441
Mona Park	$2,139,184	$2,715,665	$576,481
Mount Garnet	$2,084,568	$3,222,862	$1,138,294
Pleystowe	$3,292,846	$3,500,018	$207,172
Rockhampton South	$1,097,615	$3,181,276	$2,083,661
Sarina	$2,252,745	$1,123,410	-$1,129,335
Tennyson Street	$2,252,745	$3,428,475	$1,175,730
Victoria	$1,069,592	$4,478,129	$3,408,537
Yarranlea	$2,195,231	$7,289,169	$5,093,939
Total	**$33,625,890**	**$79,959,305**	**$46,333,415**

It is noted that one site (Sarina) provides a negative NPV based on the risk quantification conducted. While this individual result is negative, the overall program is positive and is supported by the risk quantification analysis.

3.4 Scenario Analysis

3.4.1 Sensitivities

Two of the key drivers of the quantitative risk assessment have been flexed for a marginal NPV site (Mona Park) and a higher CAPEX site (Jarvisfield) to test the suitability of the proposed options. The inputs flexed were:

- **Asset characteristic life**: This value drives the Weibull distribution which was used to assess the likelihood of asset failure. In general, a higher characteristic life will result in a lower likelihood of failure for the asset.
- **Total Load Transfers Available:** A significant component of the risk attached to transformer failure is the customer load at risk until a replacement unit is installed. The amount of transfers that can occur is a key driver of how much load is left at risk until the failed transformer is replaced.

The impact of flexing these two inputs on the NPV for each site are summarised in Table 5**Error! Reference source not found.**.

Table 5: Sensitivity analysis on key inputs for select sites (NPV $ millions)

Substation	Base NPV	Characteristic Life		Load Transfers Available	
		-5 years	+5 years	-1MW	+1MW
Mona Park	0.58	1.49	-0.05	0.77	0.38
Jarvisfield	1.39	2.43	0.64	1.68	1.10

The only negative result is for Mona Park when the characteristic life is flexed up to 84 years. However, the 79 years used in the model is already a conservative value and it is therefore reasonable to treat the Mona Park model as a positive result.

3.4.2 Value of regret analysis

In terms of selecting a decision pathway of 'least regret', Option 2 presents an economically efficient balanced approach to investment by targeting replacement works based on assessed condition and reducing risk to the greatest extent without bringing forward unnecessary expenditure.

The key regret identified in this business case is the potential loss of power transformation services, leading to negative safety outcomes (e.g. a fatality or serious injury), customer load interruption or environmental harm. Customer load interruption is the key driver of the risk assessment, as the value of customer reliability (VCR) leads to significant risk 'costs' for extended outages.

The economic value of this risk has been quantified as part of the analysis, with Option 2 delivering a $74.8 million benefit in terms of reduced total risk (as compared to Option 1). Option 2 therefore produces the lower risk cost in relation to total risk.

3.5 Qualitative comparison of identified options

3.5.1 Advantages and disadvantages of each option

Table 6 below details the advantages and disadvantages of each option considered.

Table 6: Assessment of options

Pros	Advantages	Disadvantages
Option 1 – 'Run-to-Failure' (Counterfactual)	• Reduces capital expenditure in the regulatory period	• Will substantially increase customer load disruption, as failure in-service is likely to prevent customers receiving power • Will increase the likelihood of catastrophic failure, with negative safety consequences for staff and the public
Option 2 – Condition Based Replacement	• Leads to the greatest reduction in quantified risk across all the assessed substation sites	• Brings forward capital expenditure that could be deferred to the next regulatory period, increasing short-term customer price pressure

3.5.2 Alignment with network development plan

The preferred option aligns with the Asset Management Objectives in the Distribution Annual Planning Report. In particular, it manages risks, performance standards and asset investment to deliver balanced commercial outcomes while modernising the network to facilitate access to innovative technologies.

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, and represents prudent asset management and investment decision-making to support optimal customer outcomes and value across short, medium and long-term horizons.

3.5.4 Risk Assessment Following Implementation of Proposed Option

Table 7: Risk assessment showing risks mitigated following Implementation

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Interruption of customer load – A substation transformer fails in-service, leaving customer load unserved while load is transferred, back-up generation mobilised, and capacity is eventually restored at the affected substation site.	Customer	*(Original)* 3 *Time to restore service exceeds 12 hours.* (Mitigated) 3 *(Time to restore service exceeds 12 hours)*	3 *(Unlikely)* 2 *(Very unlikely)*	***9*** ***(Low Risk)*** **6** ***(Low Risk)***	2025
Increased load at other sites – Transfer of load to other substations in response to a transformer failure will lead to an abnormal network configuration, leading to higher than usual load at other sites. This may accelerate the degradation of other transformer assets.	Business	*(Original)* 3 *(Abnormal network configuration)* (Mitigated) 3 *(Abnormal network configuration)*	3 *(Unlikely)* 2 *(Very unlikely)*	9 ***(Low Risk)*** **6** ***(Low Risk)***	2025
Catastrophic failure – Multiple serious injuries occur because staff members or members of the public are in the vicinity when a transformer fails catastrophically.	Safety	*(Original)* 4 *(Multiple serious injuries)* (Mitigated) 4 *(Multiple serious injuries)*	3 *(Unlikely)* 2 *(Very unlikely)*	**12** ***(Moderate Risk)*** **8** ***(Low Risk)***	2025
Oil leakage – Some substations have inadequate bunding to prevent an oil spill and soil contamination in the event a transformer fails or leaks in-service.	Environment	*(Original)* 5 *(Long term contamination of the environment)* 5 *(Long term contamination of the environment)*	3 *(Unlikely)* 2 *(Very unlikely)*	**15** ***(Moderate Risk)*** **10** ***(Low Risk)***	2025

4 Recommendation

4.1 Preferred option

The preferred option for this business case is Option 2 – Risk Based Replacement. Under this option, substation power transformers are considered for replacement once the benefits that result from their replacement outweigh the costs of doing so (assessed via a quantitative risk assessment process).

This option prudently manages the risk associated with poor condition or flawed transformers, reducing the risk of in-service failure without unnecessarily bringing forward capital costs.

4.2 Scope of preferred option

The replacement schedule and associated CAPEX (in real 2018/19 dollars) across the 2020-25 regulatory period is outlined in Table 7**Error! Reference source not found.** for transformers. The total program expenditure over the regulatory period is therefore $36.7 million (in real 2019/20 dollars), with 31 substation transformers being replaced.

Table 8: Planned replacement volume and expenditure

	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Transformers	7	2	6	8	8	31
CAPEX ($ 000s)	981	1,770	6,480	11,515	16,025	$36.7

The expenditure information in this business case is represented in the same manner as the Reset RIN Repex template. For example, if a project/program contains multiple assets (e.g.: OH conductor, poles & pole top structures), the total expenditure is apportioned to respective RIN assets individually as per the Ergon Energy RIN expenditure allocation methodology.

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).

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

Energy Queensland, *Asset Management Plan, Substation Transformers [7.041]*, (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).

Powerlink, Dr Dan Martin & Prof. T. Saha, *Power Transformer Failure Survey and Modelling Reliability - Update and Looking Ahead,* (22 August 2017), University of Queensland CIGRE AP A2 Open Day

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
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
DNSP	Distribution Network Service Provider
EQL	Energy Queensland Ltd
IT	Information Technology
KRA	Key Result Areas
kV	Kilovolt
MSS	Minimum Service Standard
MVA	Megavolt Ampere
NAR	Network Access Restriction
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
OPEX	Operational Expenditure

Abbreviation or acronym	Definition
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
WACC	Weighted average cost of capital
ZS	Zone Substation

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

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

Table 9: Alignment with NER

Capital Expenditure Requirements	Rationale
6.5.7 (a) (2) The forecast capital expenditure is required in order to **comply with all applicable regulatory obligations or requirements** associated with the provision of standard control services	This program is required to manage safety risks in accordance with the Electrical Safety Act and associated Regulations.
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	The failure of these assets is likely to impact reliability; hence this proposal addresses the reliability of supply.
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.	This program is required to manage safety risks in accordance with the Electrical Safety Act and associated Regulations.
6.5.7 (c) (1) (i) The forecast capital expenditure reasonably reflects the **efficient costs** of achieving the capital expenditure objectives	The Unit Cost Methodology and Estimation Approach sets out how the estimation system is used to develop project and program estimates based on specific material, labour and contract resources required to deliver a scope of work. The consistent use of the estimation system is essential in producing an efficient CAPEX forecast by enabling: • Option analysis to determine preferred solutions to network constraints • Strategic forecasting of material, labour and contract resources to ensure deliverability • Effective management of project costs throughout the program and project lifecycle, and • Effective performance monitoring to ensure the program of work is being delivered effectively. The unit costs that underpin our forecast have also been independently reviewed to ensure that they are efficient (Attachments 7.004 and 7.005).
6.5.7 (c) (1) (ii) The forecast capital expenditure reasonably reflects the costs that **a prudent operator** would require to achieve the capital expenditure objectives	The prudency of this proposal is demonstrated through the options analysis conducted and the quantification of risk and benefits of each option. The prudency of our CAPEX forecast is demonstrated through the application of our common frameworks put in place to effectively manage investment, risk, optimisation and governance of the Network Program of Work. An overview of these frameworks is set out in our Asset Management Overview, Risk and Optimisation Strategy (Attachment 7.026).

Appendix D. Mapping of Asset Management Objectives to Corporate Plan

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

Table 1: "Asset Function and Strategic Alignment" in Section 1.4 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 10: Alignment of Corporate and Asset Management objectives

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

Appendix E. Risk Tolerability Table

<table>
<tr><th colspan="5">Network Risks - Risk Tolerability Criteria and Action Requirements</th><th></th></tr>
<tr><th>Risk Score</th><th>Risk Descriptor</th><th colspan="3">Risk Tolerability Criteria and Action Requirements</th><th></th></tr>
<tr><td>30 – 36</td><td colspan="4">Intolerable
(stop exposure immediately)</td><td></td></tr>
<tr><td>24 – 29</td><td>Very High Risk</td><td rowspan="5">*ALARP
Risk in this range managed to As Low As Reasonably Practicable</td><td>Executive Approval
(required for continued risk exposure at this level)</td><td>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</td><td rowspan="5">SFAIRP
Risks in this area to be mitigated So Far as is Reasonably Practicable</td></tr>
<tr><td>18 – 23</td><td>High Risk</td><td>Divisional Manager Approval
(required for continued risk exposure at this level)</td><td>Introduce new or changed risk treatments to reduce level of risk
Periodic review of the risk and effectiveness of the existing risk treatments</td></tr>
<tr><td>11 – 17</td><td>Moderate Risk</td><td rowspan="2">Group Manager / Process Owner Approval
(required for continued risk exposure at this level)</td><td rowspan="2">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</td></tr>
<tr><td>6 – 10</td><td>Low Risk</td></tr>
<tr><td>1 to 5</td><td>Very Low Risk</td><td>No direct approval required but evidence of ongoing monitoring and management is required</td><td>Periodic review of the risk and effectiveness of the existing risk treatments</td></tr>
</table>

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

Appendix F. Quantitative Risk Assessment Details

Data Input			
		Description/Justification	**Source**
Asset Class	Power Transformers	-	-
Asset Median Life (years)	113.4	-	Calculated from the Weibull Parameters
NPV Period (years)	30	-	-
Unit Rate ($)	1,186,168	Average forecasted expenditure within the 2020-2025 regulatory period.	Attachment 7.076 of our initial regulatory proposal.
Emergency Replacement Cost Multiplier	1.30	Scaling factor for emergency replacement works. Based on the added costs involved with replacements when responding to a failure in-service event	Assumed based on EQL and peer organisation industry experience.

Deployment of Spare Transformer			
		Description/Justification	**Source**
Prepare (hours)	100	Time taken to prepare a spare transformer. Based on if the substation has a N-1 scheme	Input data provided by EQ and reviewed by Aurecon
Mobilise (hours)	250	Time taken to mobilise a spare transformer. Based on location of depts and anticipated availability of spares	Input data provided by EQ and reviewed by Aurecon
Install (hours)	286	Time taken to install a spare transformer. Based on location of depts and anticipated availability of spares	Input data provided by EQ and reviewed by Aurecon

Backup Generation				
			Description/Justification	**Source**
Transfers	**Switching Time (hours)**	3	Time taken to switch at the substation to provide alternate supply. Based on labour involved with triggering a switching transfer.	Input data provided by EQ and reviewed by Aurecon
	Total Power Transferred (MW)	-	Power capacity of available transfers. Site specific.	Input data provided by EQ and reviewed by Aurecon
Backup Generator	**Time to get online (hours)**	-	Time taken to get a backup generator online in case of a failure. Site specific based on labour involved with the available backup generator.	Input data provided by EQ and reviewed by Aurecon
	Power (MW)	-	The capacity available from the backup generator. Site specific.	Input data provided by EQ and reviewed by Aurecon
	Cost of Diesel ($/MWh)	392	Cost of running a diesel generator.	Sourced internally from Aurecon

Customer Risk Inputs				
			Description/Justification	**Source**
Residential	**VCR ($/MWH)**	25,420	The value different types of customers place on having reliable electricity supplies under different conditions. Determined from survey results conducted by AEMO.	AEMO Value of Customer Reliability Fact Sheet
	Substation Total Load (MVA)	-	Site specific load lost per transformer failure.	Input data provided by EQ
	Power Factor	0.85	The ratio which determines the real power used by EQL residential customers. Based on the typical uncompensated power factor for an EQL zone substation.	EQL 2018 DAPR – typical values
	Load Factor	-	A ratio of average load to peak load within a specific time. Acts as a measure of EQL's utilisation rate. Site specific.	As agreed with EQL.
	Percentage of Mix	-	Percentage of the zone substation customer mix. Site specific.	Input data provided by EQ
Commercial	**VCR ($/MWH)**	44,390	-	AEMO Value of Customer Reliability Fact Sheet
	Substation Total Load (MVA)	-	Site specific load lost per transformer failure.	Input data provided by EQ
	Power Factor	0.85	Based on typical uncompensated power factor for an EQ zone substation	EQ 2018 DAPR
	Load Factor	-	Site specific information used	Input data provided by EQ
	Percentage of Mix	-	Percentage of the zone substation customer mix. Site specific.	Input data provided by EQ

Safety Risk Inputs				
Consequence	**Monetisation ($)**	**Disproportionality Factor**	**Description/Justification**	**Source**
Single Fatality	4,900,000	10	Cost of a single fatality scaled by factor of 10.	[1] The sources used to develop the Disproportionality Factors are as follows: Ausgrid - Revised Proposal - Attachment 5.13.M.4 - Low Voltage Overhead Service Lines program CBA summary - January 2019 https://www.pmc.gov.au/sites/default/files/publications/value-of-statistical-life-guidance-note_0_0.pdf https://www.hse.gov.uk/risk/theory/alarpcba.htm
Single Series Injury	490,000	8	Cost of a single serious injury scaled by a factor of 8.	
Fire	660,000	8	Cost of a fire scaled by a factor of 4.	

[1] Disproportionality factors are applied to the consequence monetisation to offset the gross disproportion (perceived point at which the cost of implementing a safety measure exceeds its expected benefits). The above factors are based on a review of peer organisations, as well as other industries, to identify a single factor within the approximate median of the range of factors identified in the review.

Incident Conversion Rate (ICR) & Probability of Consequence (PoC)						
ICR		PoC			Description/Justification	Source
Consequence	Incidents Attr. to Cons.	Category	Risk Scale	Probability of Severity		
Single Fatality	0.15	Safety	5	1.00%	ICR - 5% of incidents are attributed to a single fatality. Estimated based on frequency of staff maintenance and accessibility to general public PoS - 1% of incidents result in a single fatality. Based on the severity of the consequence being considered as major.	ICR - Assumed based on EQL and peer organisation industry experience. PoC - Assumed based on EQL and peer organisation industry experience.
Major Injury	0.2	Safety	4	4.00%	ICR - 7% of incidents are attributed to a major injury. Estimated based on frequency of staff maintenance and accessibility to general public. PoS - Based on the severity of the consequence being considered as moderate to major.	ICR - Assumed based on EQL and peer organisation industry experience. PoC - Assumed based on EQL and peer organisation industry experience.
Customer Outage	3	Customer	1	4.00%	ICR - 100% of incidents are attributed to customer outages. Assuming transformer functional failures result in an outage only where there is no redundancy, or when two transformers at a substation fail simultaneously. Assuming transformer catastrophic failures result in an outage. PoS - 100% of incidents result in a customer outage	ICR - Assumed based on EQL and peer organisation industry experience. PoC - Assumed based on EQL and peer organisation industry experience.
Fire	1	Fire	3	1%	ICR - 33% of incidents are attributed to a fire. Calibrated based on the expected costs involved with fire risks relative to costs involved with safety, and oil hazards involved with the asset. PoC – 1% of incidents result in a fire. Based on the severity of the consequence being considered as minor to moderate.	ICR - Assumed based on EQL and peer organisation industry experience. PoC - Assumed based on EQL and peer organisation industry experience.
Environment	0.5	Environment	2	50.00%	ICR - 17% of incidents are attributed to an environmental issue. Estimated based on oil hazards involved with the asset and typical	ICR - Assumed based on EQL and peer organisation industry experience.

Incident Conversion Rate (ICR) & Probability of Consequence (PoC)						
					location of transformers in a substation. PoS – Site specific, different figures used depending on bunding arrangements	PoC - Assumed based on EQL and peer organisation industry experience.
Diesel	3	Diesel	1	100%	ICR - 100% of incidents are attributed to customer outages and hence a requirement for diesel backup generators. Assuming transformer functional failures result in an outage only where there is no redundancy, or when two transformers at a substation fail simultaneously. Assuming transformer catastrophic failures result in an outage. PoS - 100% of incidents result in diesel generators.	ICR - Assumed based on EQL and peer organisation industry experience. PoC - Assumed based on EQL and peer organisation industry experience.
Total No. of Incidents	**3**					

Reliability Model					
				Description/Justification	**Source**
No. of Transformers Existing	-			Amount of power transformers currently at the substation	Input data provided by EQ
No. of Transformers Replaced	-			Amount of power transformers to be replaced at the substation	Input data provided by EQ
Tx Parameter Set	*Tx [1]*	*Tx [2]*	*Tx [3]*	-	-
Shape parameter (β)	3.6	3.6	3.6	-	*Power transformer failure survey and modelling reliability - update and looking ahead* presentation CIGRE AP A2 open day 22/8/17, Powerlink/UQ
Characteristic life (η)	79	79	79	-	*Power transformer failure survey and modelling reliability - update and looking ahead* presentation CIGRE AP A2 open day 22/8/17, Powerlink/UQ
Transformer Age at 2020	-	-	-	Current age of existing transformer/s.	Input data provided by EQ
Replacement Year from 2020	-			Year at which the replacement transformer/s will be installed	Input data provided by EQ

Appendix G. Reconciliation Table

Reconciliation Table Conversion from $18/19 to $2020	
Business Case Value	
(M$18/19)	$36.70
Business Case Value	
(M$2020)	$38.30