Regulatory Investment Test for Distribution (RIT-D)

Addressing Reliability Requirements in the Craiglie Network Area

Final Project Assessment Report

25 July 2025

ERGON ENERGY NETWORK

Part of Energy Queensland

EXECUTIVE SUMMARY

About Ergon Energy

Ergon Energy Corporation Limited (Ergon Energy) is part of Energy Queensland and manages an electricity distribution network which supplies electricity to more than 765,000 customers. Our vast operating area covers over one million square kilometres (around 97% of the state of Queensland) from the expanding coastal and rural population centres to the remote communities of outback Queensland and the Torres Strait.

Our electricity network consists of approximately 160,000 kilometres of powerlines and one million power poles, along with associated infrastructure such as major substations and power transformers.

We also own and operate 33 stand-alone power stations that provide supply to isolated communities across Queensland which are not connected to the main electricity grid.

Identified Need

Craiglie 132/22kV Substation (CRAI) provides electricity supply to approximately 4,462 customers in the Port Douglas area, of which 3,734 are residential and 728 are commercial and industrial. CRAI supplies 97.8 GWh of energy annually, with 33% of this energy consumed by residential customers.

Condition Based Risk Management (CBRM) analysis has identified that the two 15/20MVA English Electric 132/22kV transformers (YOM 1967) and protection relays at CRAI are reaching end of life. The ongoing operation of these assets beyond their estimated retirement date presents significant safety, environmental and customer reliability risks.

The deterioration of these primary and secondary system assets poses safety risks to staff working within the switchyard. It also poses a safety risk to the general public, through the increased likelihood of protection relay mal-operation. Ergon Energy has obligations under the *Electrical Safety Act 2002* (Qld)[1] to eliminate electrical safety risks so far as is reasonably practicable, and where not reasonably practicable, to minimise the risks so far as is reasonably practicable.

Additionally, the poor condition of these assets significantly increases the likelihood of outages, resulting in a reduction in the level of reliability experienced by the customers supplied from CRAI. The CRAI transformers also have a 2.1MVA reverse power flow limitation due to their single switching resistor type tap changers, which could limit export from future customer PV systems.

[1] QLD Electrical Safety Act 2002:
Part 2, Subdivision 2, Section 28 - What is reasonably practicable in ensuring electrical Safety
Part 2, Division 2, Section 29 - Duty of electricity entity

Addressing Reliability Requirements in the Craiglie Network Area Final Project Assessment Report

Ergon Energy has obligations to comply with reliability performance standards specified in its Distribution Authority[2] issued under the *Electricity Act 1994* (Qld). Further to these requirements, the *Electricity Act 1994* (Qld)[3] stipulates that distribution entities must comply with the reliability requirements, system standards and performance requirements specified in the National Electricity Rules (NER)[4].

Ergon Energy is seeking to invest in the network to undertake a reliability corrective action in order to continue to meet the service standards in its applicable regulatory instruments (National Electricity Rules, *Electricity Act 1994* (Qld), *Electrical Safety Act 2002* (Qld)).

Approach

The National Electricity Rules (NER) require that, subject to certain exclusion criteria, network business investments for meeting service standards for a distribution business are subject to a Regulatory Investment Test for Distribution (RIT-D). Ergon Energy has determined that network investment is essential in this case for it to continue to provide electricity to the consumers in the Craiglie supply area in a reliable, safe and cost-effective manner. Accordingly, this investment is subject to a RIT-D.

One potentially feasible option has been investigated:

- **Option A:** Replace both 132/22kV transformers and protection relays at CRAI in 2027.

This Final Project Assessment Report (FPAR), has been prepared in accordance with the requirements of clause 5.17.4 of the NER.

Ergon Energy's preferred option to address the identified need is Option A, to replace both 132/22kV transformers and protection relays at CRAI in 2027.

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[2] Ergon Energy Distribution Authority:
Section 7 - Guaranteed Service Levels
Section 8 - Distribution Network Planning
Section 9 - Minimum Service Standards
Section 10 – Safety Net

[3] QLD Electricity Act 1994 Part 5, Division 5, Section 42(a)(i)

[4] NER:
Schedule 5.1a System Standards
Schedule 5.1 Network Performance Requirements

CONTENTS

1. INTRODUCTION

This Final Project Assessment Report (FPAR) has been prepared by Ergon Energy in accordance with the requirements of clause 5.17.4 of the NER.

This FPAR represents the final stage of the consultation process in relation to the application of the RIT-D on potential credible options to address the identified need for the Craiglie network area.

In preparing this FPAR, Ergon Energy is required to consider reasonable future scenarios. With respect to major customer loads and generation, Ergon Energy has, in good faith, included as much detail as possible while maintaining necessary customer confidentiality. Potential large future connections that Ergon Energy is aware of are in different stages of progress and are subject to change (including outcomes where none or all proceed). These and other customer activity can occur over the consultation period and may change the timing and/or scope of any proposed solutions.

1.1. Structure of the Report

This report:

- Provides background information on the network limitations of the distribution network supplying the Craiglie area.
- Identifies the need which Ergon Energy is seeking to address, together with the assumptions used in identifying and quantifying that need.
- Describes the credible options that are considered in this RIT-D assessment.
- Quantifies costs and classes of material market benefits for each of the credible options.
- Quantifies the applicable costs for each credible option, including a breakdown of operating and capital expenditure.
- Describes the methods used in quantifying each class of market benefit.
- Provides details of classes of market benefits that are not considered material to this RIT-D assessment and provides explanations as to why these classes of market benefits are not considered material.
- Provides the results of Net Present Value (NPV) analysis of each credible option and accompanying explanatory statements regarding the results.
- Identifies the proposed preferred option, including detailed characteristics, estimated commissioning date, indicative costs, and noting that it satisfies the RIT-D.
- Provides contact details for queries on this RIT-D.

1.2. Dispute Resolution Process

In accordance with the provisions set out in clause 5.17.5 of the NER, Registered Participants and other interested stakeholders may, within 30 days after the publication of this report, dispute the conclusions made by Ergon Energy in this report with the Australian Energy Regulator. Any parties raising a dispute are also required to notify Ergon Energy. Dispute notifications should be sent to demandmanagement@ergon.com.au

If no formal dispute is raised, Ergon Energy will proceed with the preferred network option, to replace both 132/22kV transformers and protection relays at CRAI in 2027.

1.3. Contact Details

For further information and inquiries please contact:

E: demandmanagement@ergon.com.au
P: 13 74 66

2. BACKGROUND

2.1. Geographic Region

Craiglie 132/22kV Substation (CRAI) provides electricity supply to approximately 4,462 customers in the Port Douglas area, of which 3,734 are residential and 728 are commercial and industrial. CRAI supplies 97.8 GWh of energy annually, with 33% of this energy consumed by residential customers.

The geographical location of Ergon Energy's sub-transmission network and substations in the area is shown in Figure 1.

Figure 1: Existing network arrangement (geographic view)

2.2. Existing Supply System

CRAI is located in the Port Douglas area in Far North Queensland and is supplied by a double circuit 132kV feeder from T055 Turkinje 132/66kV Substation (TURK).

CRAI was established in 1996 according to applicable design and construction standards during that time. CRAI consists of 2 x 132/22kV 15/20MVA (ONAN/ONAF) power transformers and an indoor 22kV switchboard with 5 x 22kV feeders.

A schematic view of the existing sub-transmission network arrangement is shown in Figure 2 and the geographic view of CRAI is illustrated in Figure 3.

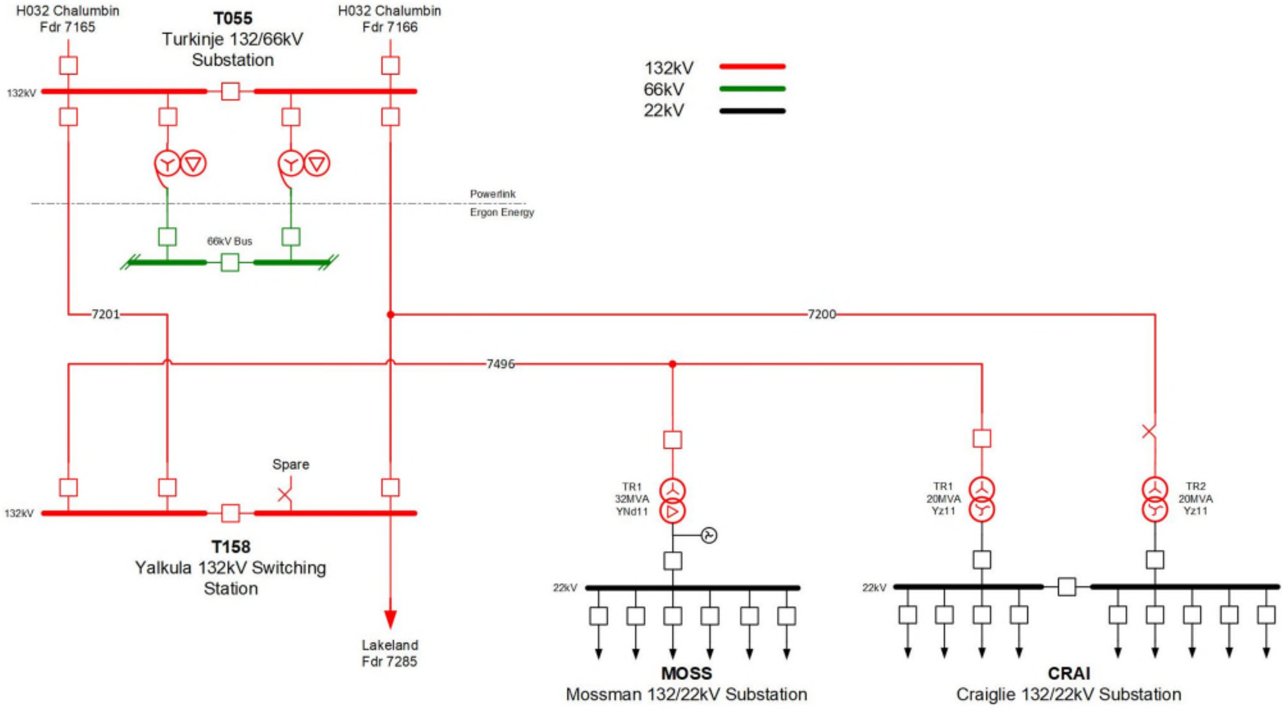

Figure 2: Existing network arrangement (schematic view)

Figure 3: Craiglie Substation (geographic view)

2.3. Load Profiles / Forecasts

The load at CRAI comprises a mix of residential and commercial customers. The load is Summer peaking, and the annual peak loads are predominantly driven by residential and commercial load. The annual minimum load generally occurs during the Winter period around 3am in the morning, however this is forecast to shift to the Winter midday period once export from rooftop solar PV systems starts to exceed the daytime load in the area.

2.3.1. Full Annual Load Profile

The full annual load profile for CRAI over the 2023/24 and 2024/25 financial years is shown in Figure 4. Note that since mid-2024 CRAI has temporarily supplied some of the Mossman substation load while works are undertaken at Mossman substation, therefore the load for this period is higher than the normal CRAI load.

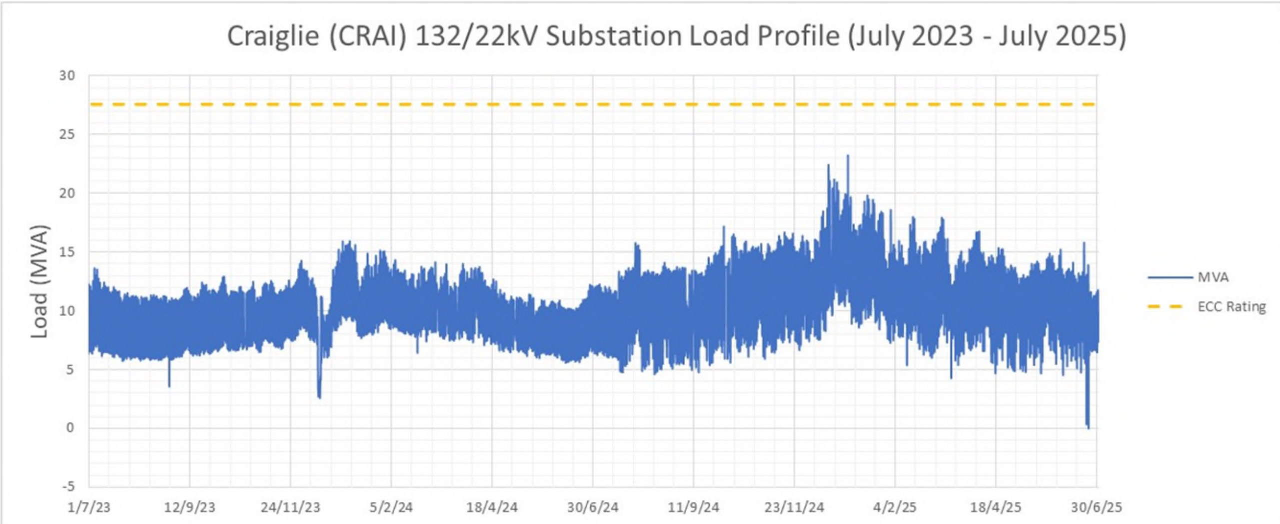

Figure 4: Substation actual annual load profile

2.3.2. Load Duration Curve

The load duration curve for CRAI over the 2023/24 and 2024/25 financial years is shown in Figure 5.

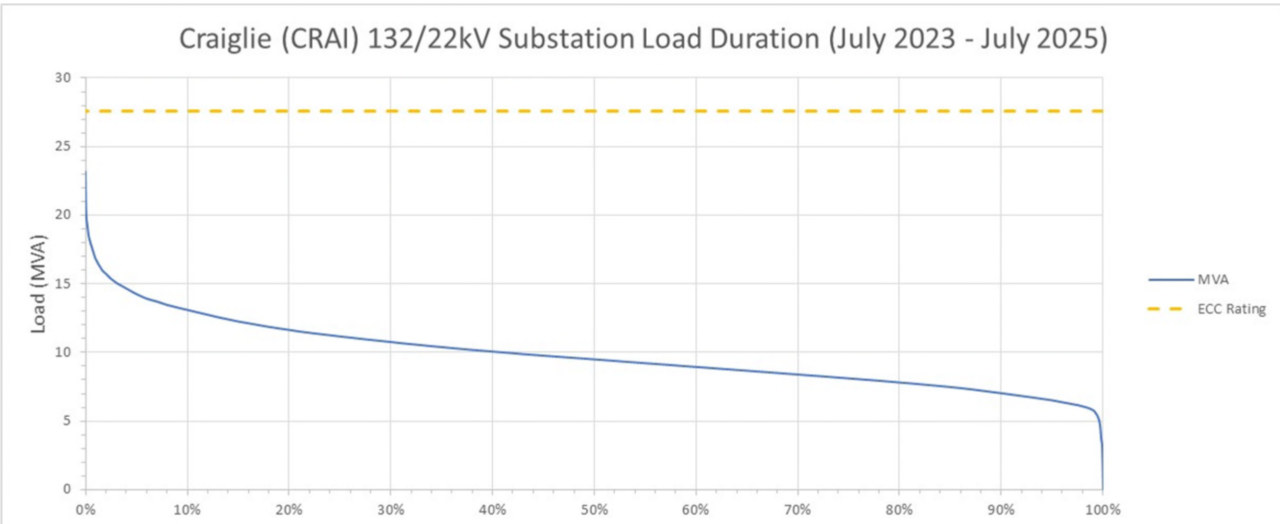

Figure 5: Substation load duration curve

2.3.3. Average Peak Weekday Load Profile (Summer)

The daily load profile for an average peak day during Summer is illustrated below in Figure 6. It can be noted that the Summer peak loads at CRAI are historically experienced in the late afternoon and evening.

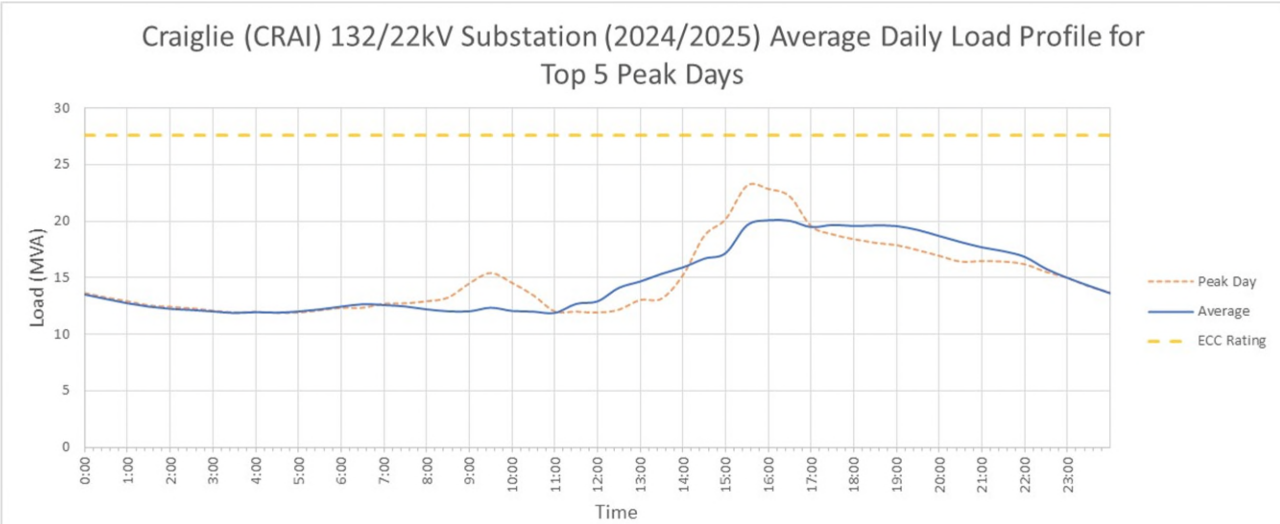

Figure 6: Substation average peak day load profile (Summer)

2.3.4. Base Case Load Forecast

The 10 PoE (10% probability of exceedance) and 50 PoE (50% probability of exceedance) load forecasts for the base case load growth scenario are illustrated in Figure 7. The historical peak load for the past six years has also been included in the graph.

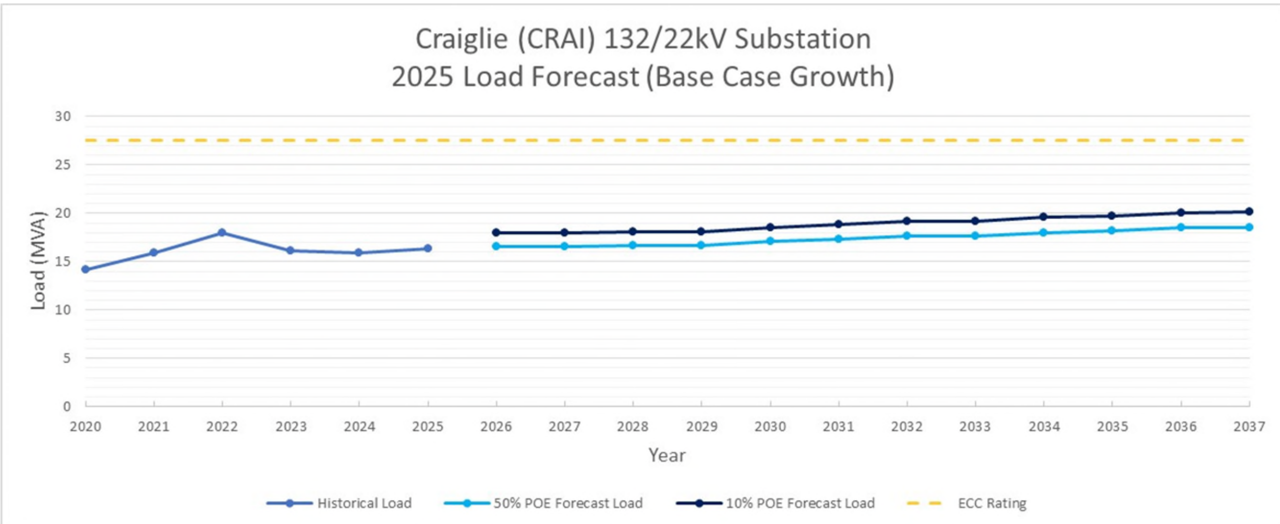

Figure 7: Substation base case load forecast

2.3.5. High Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the high load growth scenario are illustrated in Figure 8. With the high growth scenario, the peak load is forecast to increase over the next 10 years.

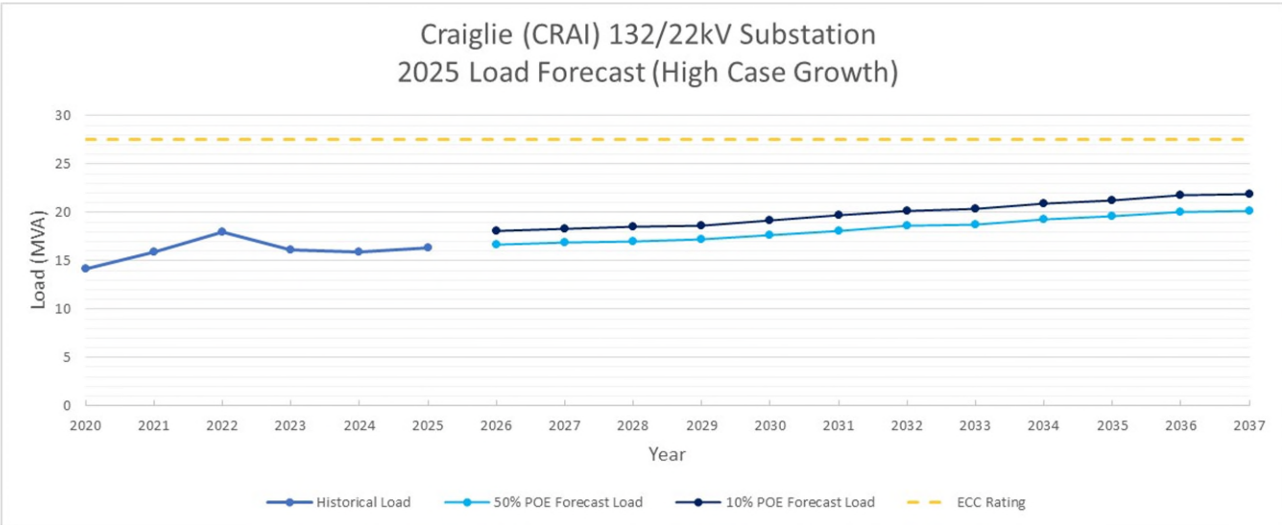

Figure 8: Substation high growth load forecast

2.3.6. Low Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the low load growth scenario are illustrated in Figure 9. With the low growth scenario, the peak load is forecast to remain relatively steady over the next 10 years.

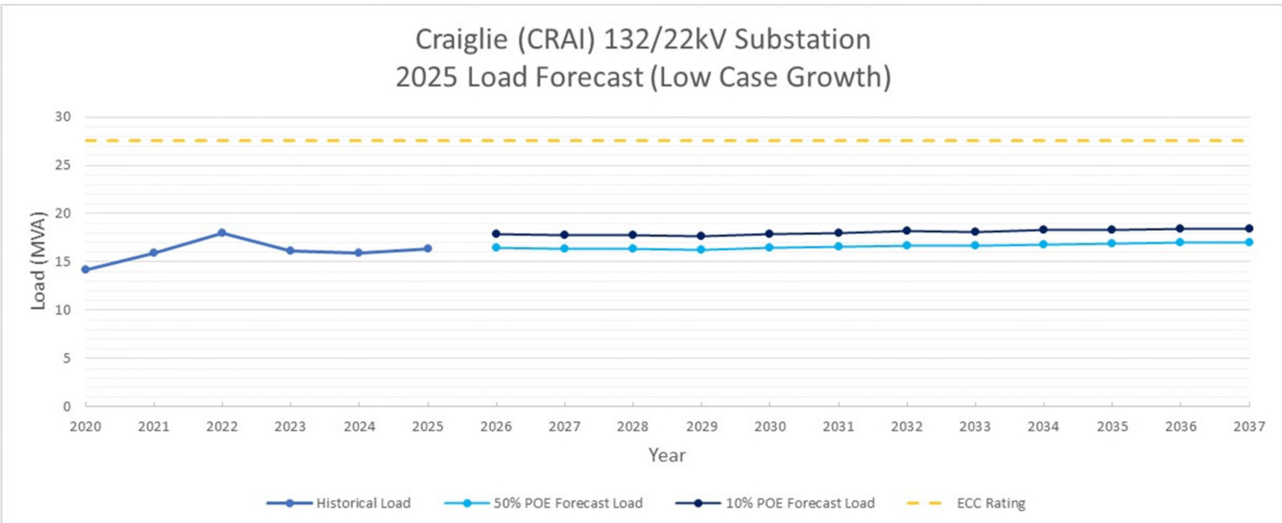

Figure 9: Substation low growth load forecast

2.3.7. Minimum Demand Forecast

The minimum demand forecast at CRAI with the impact of connected solar PV systems is decreasing as illustrated in Figure 10. The reverse power flow capacity of CRAI is limited by the single switching resistor type tap changer of the transformer with a system normal rating of 4.2MVA with both transformers in service and a contingent rating of 2.1MVA with one of the transformers out of service. With each of the solar PV uptake scenarios, the minimum demand forecast is showing reverse power flows at CRAI that are forecast to exceed the reverse power flow capacity over the next 10 years.

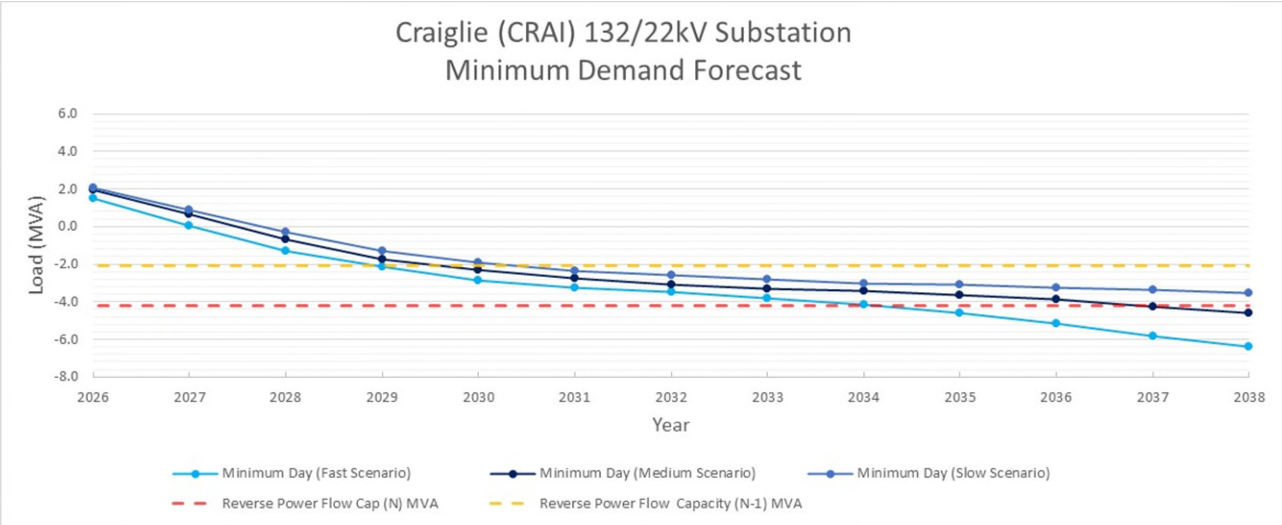

Figure 10: Minimum Demand forecast

3. IDENTIFIED NEED

3.1. Description of the Identified Need

3.1.1. Reliability Corrective Action

Condition Based Risk Management (CBRM) analysis has identified that the two 15/20MVA English Electric 66/11kV transformers (YOM 1967) and protection relays at CRAI are reaching end of life. The ongoing operation of these assets beyond their estimated retirement date presents significant safety, environmental and customer reliability risks.

The deterioration of these primary and secondary system assets poses safety risks to staff working within the substation. It also poses a safety risk to the general public, through the increased likelihood of protection relay mal-operation. Ergon Energy has obligations under the *Electrical Safety Act 2002* (Qld)[5] to eliminate electrical safety risks so far as is reasonably practicable, and where not reasonably practicable, to minimise the risks so far as is reasonably practicable.

Additionally, the poor condition of these assets significantly increases the likelihood of outages, resulting in a reduction in the level of reliability experienced by the customers supplied from CRAI. The CRAI transformers also have a 2.1MVA reverse power flow limitation due to their single switching resistor type tap changers, which could limit export from future customer PV systems.

Ergon Energy has obligations to comply with reliability performance standards specified in its Distribution Authority[6] issued under the *Electricity Act 1994* (Qld). Further to these requirements, the *Electricity Act 1994* (Qld)[7] stipulates that distribution entities must comply with the reliability requirements, system standards and performance requirements specified in the National Electricity Rules (NER)[8].

Where Ergon Energy identifies an imminent asset safety risk, immediate temporary measures are put in place to ensure safety of staff and public until permanent remediation can be performed.

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[5] QLD Electrical Safety Act 2002:
Part 2, Subdivision 2, Section 28 - What is reasonably practicable in ensuring electrical Safety
Part 2, Division 2, Section 29 - Duty of electricity entity

[6] Ergon Energy Distribution Authority:
Section 7 - Guaranteed Service Levels
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[7] QLD Electricity Act 1994 Part 5, Division 5, Section 42(a)(i)

[8] NER:
Schedule 5.1a System Standards
Schedule 5.1 Network Performance Requirements

3.2. Quantification of the Identified Need

The benefits of each credible option are assessed against the counterfactual, which in this case is to continue to operate the network with existing in-service assets. Existing maintenance regime would continue and equipment that fails in service would be replaced like for like through an urgent replacement project.

3.2.1. Risk Quantification Value Streams

The risk quantification of the counterfactual at CRAI has considered five primary value streams, *safety, environmental, reliability*, *financial* and *export* as shown in Figure 11 and described in further detail below.

- **Safety:** Maintaining substation equipment beyond the recommended retirement year presents increasing safety risks to substation staff and the public. E.g. there is an increased chance of catastrophic failure of a transformer which could cause severe injuries to workers within the substation. Mal-operation of protection relays can lead to unsafe conditions on the network which presents a risk to staff and the public.
- **Environmental:** In the event of a catastrophic failure of one of the transformers, there is a risk of environmental harm due to an oil spill beyond the substation perimeter, which would require clean up and rectification.
- **Reliability:** There is potential unserved energy within the Port Douglas network area following an outage at CRAI.
- **Financial:** Replacing single assets on failure as individual failed in-service projects has been assumed to incur a 30% increase in cost in comparison to a planned project.
- **Export:** There is potential customer export curtailment within the Port Douglas area due to the reverse power flow limitations on the CRAI transformers.

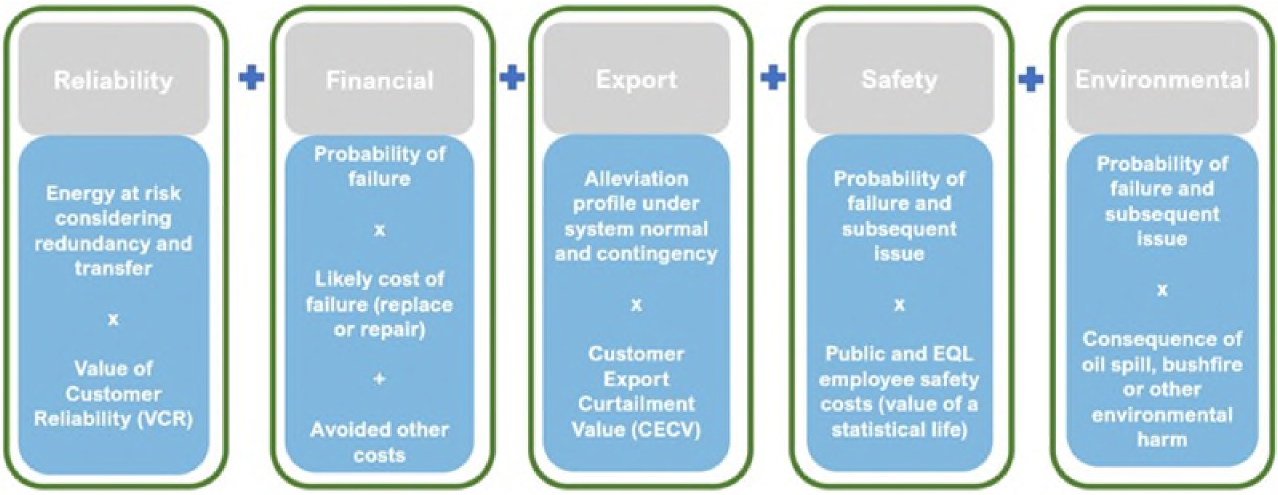


Figure 11 – Value Streams for Investment

3.2.2. Counterfactual Risk Quantification

The counterfactual risks are the expected unserved energy, emergency replacement cost, environmental risks, safety risks and customer export curtailment, during an equipment failure and associated unplanned supply outage at CRAI.

In calculating the value streams the following assumptions are used:

- **Forced Outage Rate** – The transformer outage rates are predicted using a Weibull distribution with a Shape Parameter (β) of 3.6 and a Characteristic Life (η) of 79 for a 132/22kV transformer. A flat outage rate of 0.027 has been applied for the first 4 years to capture the increased risk of failure in the first years of a transformers life.
- **Restoration** – following a transformer outage it has been estimated that the average rectification time would be 48 hours.
- **Transfers** – manual transfer capacity of 3 MVA via 22kV feeder ties to neighbouring substations.
- **VCR Rate** – a VCR rate of $34.38 / kWh has been used for the 22kV load supplied from CRAI with the mix of customers weighted towards domestic and commercial customers. The weighting applied to each customer type is shown in Table 1.
- **CECV** – determined using the values published in the customer export curtailment value (CECV) methodology on the AER website[9].
- **Emergency replacement Cost:** On failure of assets the plant will be replaced like-for-like with an additional 30% cost in comparison to the planned project.
- **Safety** – Considers forced outage rate of the asset with a conversion factor of 0.1% that a fatality to employee and/or injury to employee will occur.
- **Risk timeframe** – the risks have been quantified over a 60-year period, starting from 2027 to align with the investment year of Option A (see below).

Figure 12 shows the quantified risk per annum for the counter-factual increasing over the 60-year period from 2027 to 2087.

The customer export curtailment risk per annum starts to increase significantly from 2039 onwards when the forecast reverse power flows start to exceed the 4.2MVA system normal rating of the CRAI transformers.

[9] https://www.aer.gov.au/industry/registers/resources/guidelines/customer-export-curtailment-value-methodology

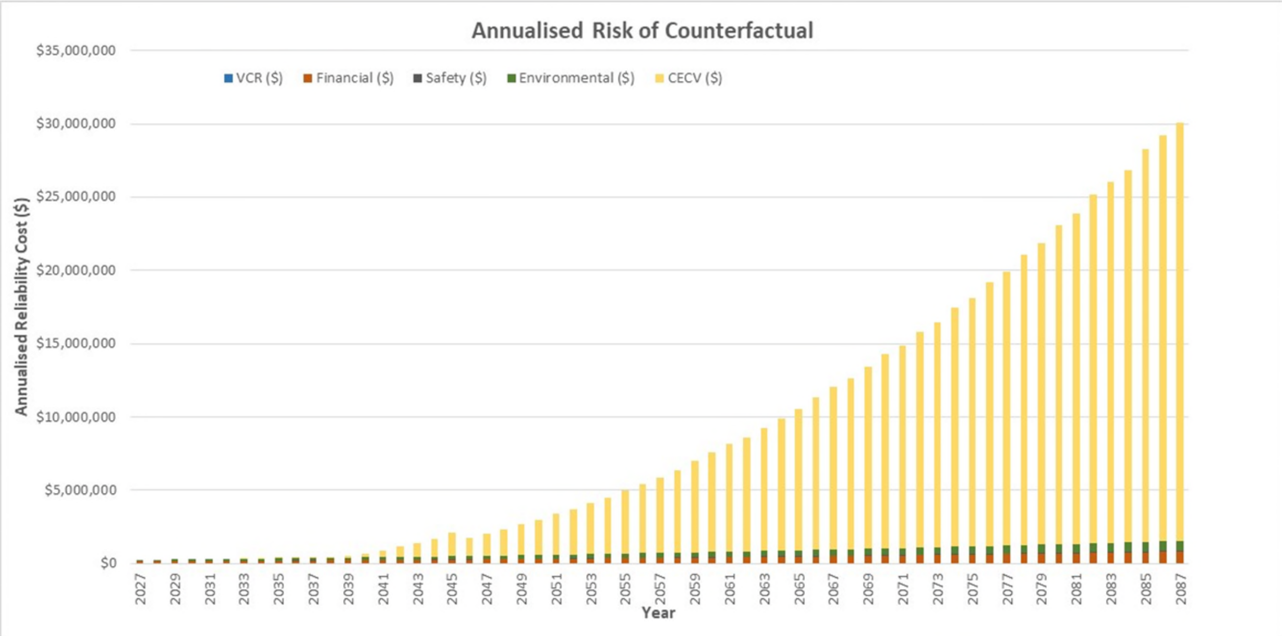


Figure 12: Annualised Risk of Counterfactual

Value of Customer Reliability (VCR) is an economic value applied to customers' unserved energy for any particular year. VCR values represent customers' willingness across the National Electricity Market (NEM) to pay for reliable electricity supply. The VCR is used for estimating market benefits that relate to reliability, such as changes in involuntary and voluntary load curtailment.

The VCR calculated for this analysis for the customers supplied from CRAI is shown in Table 1 based on the VCR values for different customer types as published by the AER.

Customers	Sector	Annual Consumption (kWh)	$/kWh (2024)
CRAI 22kV Load	Residential (Climate Zone 1)	32,308,000	$35.69
	Commercial*	59,867,813	$34.39
	Industrial*	2,227,262	$33.49
	Agriculture*	3,377,775	$22.25
	Average VCR		**$34.38**

Table 1: AER VCR values for CRAI

*Business using <10MVA peak demand

$$VCR = \frac{(Residential\ kWh\ \times\ VCR) + (Commercial\ kWh\ \times\ VCR) + (Industrial\ kWh\ \times\ VCR) +\ (Agriculture\ kWh\ \times\ VCR)}{Total\ Energy}$$

3.3. Assumptions in Relation to Identified Need

Below is a summary of key assumptions that have been made when the identified need has been analysed and quantified.

It is recognised that the below assumptions may prove to have various levels of correctness, and they merely represent a 'best endeavours' approach to predict the future identified need.

3.3.1. Forecast Maximum Demand

It has been assumed that forecast peak demand at CRAI Substation will be consistent with the base case forecast outlined in Section 2.3.4.

Factors that have been taken into account when the load forecast has been developed include the following:

- load history;
- known future developments (new major customers, network augmentation, etc.);
- temperature corrected start values (historical peak demands); and
- forecast growth rates for organic growth.

3.3.2. Load Profile

Characteristic peak day load profiles shown in Section 2.3.3 are unlikely to change significantly from year to year and the shape of the load profile is assumed to remain virtually the same with increasing maximum demand.

4. CREDIBLE OPTIONS ASSESSED

4.1. Assessment of Network Solutions

Ergon Energy has identified one credible network option that would address the identified need.

4.1.1. Option A: Replace both 132/22kV transformers and protection relays at CRAI in 2027

This option is commercially and technically feasible, can be implemented in the timeframe identified, mid-2027 and would address the identified need by replacing deteriorated assets at CRAI ensuring Ergon Energy continues to adhere to the applicable regulatory instruments.

This option involves the replacement of the 132/22kV transformers and protection relays and installation of a 132kV dead tank circuit breaker at CRAI in 2027 in order to address the identified need.

Due to the scope of works being entirely contained within the existing CRAI site, as well as the expected reliability and safety benefits of this option to the local community, there are not expected to be any social licence issues that would require additional costs to manage or increase the delivery timeline. While Ergon Energy does not anticipate any community stakeholder concerns, should any be identified, these would be addressed as part of the Ergon Energy Community Engagement Framework which is integrated into the project workflow.

The estimated capital cost of this option is $10.3 million, which has been factored into the NPV to be incurred in 2027.

The estimated capital cost comprises the following components:

- financial costs incurred in constructing or providing the credible option (including early engagement on the potential connection requirements and costs of each option).
- overheads that can be directly apportioned to the credible option.
- labour and labour related costs that can be directly attributed to providing the option.
- costs of complying with relevant laws, regulations and administrative requirements; and
- costs unique to asset replacement projects or programs.

The estimated increase in planned annual operating and maintenance costs, compared to the counterfactual, for this option is $3.5 thousand, which has been factored into the NPV.

A schematic diagram of the proposed network arrangement for Option A is shown in Figure 13.

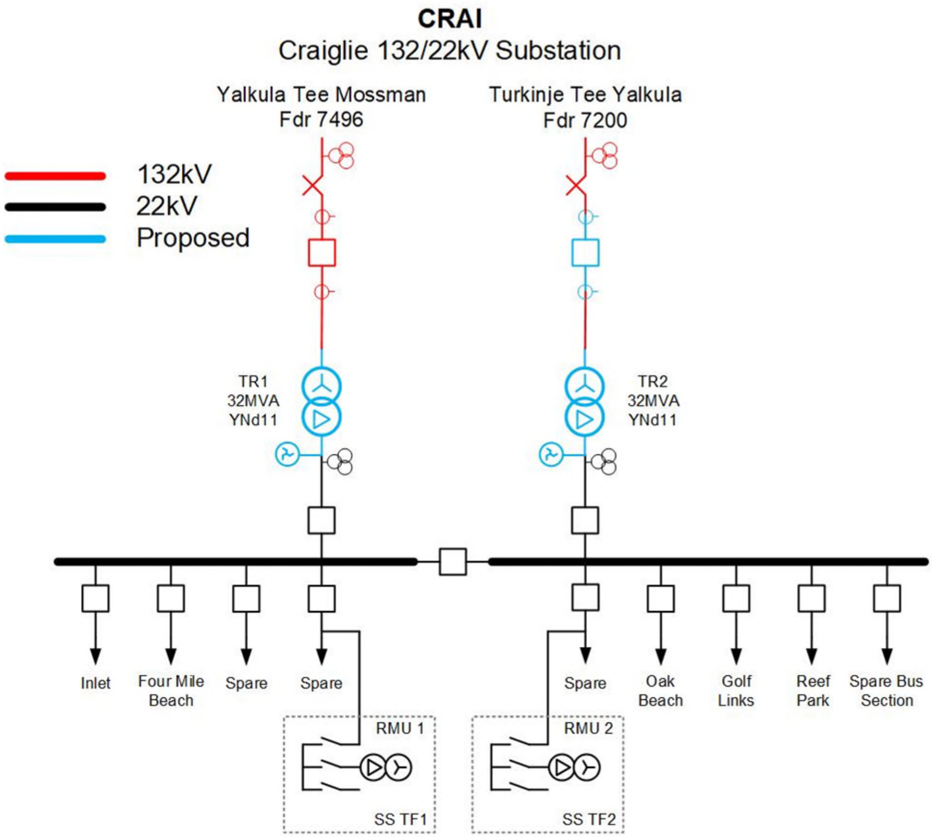


Figure 13: Option A proposed network arrangement (schematic view)

4.2. Social Licence and Community Engagement

4.2.1. Social Licence

Ergon Energy has not identified any social licence considerations that have affected the identification and selection of credible options to address the identified need.

4.2.2. Community Engagement

As the scope of works for this project will not extend into new areas of the community and will be entirely contained within the existing site owned by Ergon Energy, it is not expected to cause any disruption to the community at large. As a result, we have not identified any community stakeholders who might reasonably be expected to be affected by the development of this project.

While Ergon Energy does not anticipate any community stakeholder concerns, should any be identified, these would be addressed as part of the Ergon Energy Community Engagement Framework which is integrated into the project workflow.

4.3. Assessment of SAPS and Non-Network Solutions

Ergon Energy has considered Standalone Power Systems (SAPS) and demand management solutions. Each of these are considered below.

4.3.1. Consideration of SAPS Options

Ergon Energy considers there is no SAPS option that could form a potential credible option on a standalone basis, or that could form a significant part of the credible option. In particular the load requirements, per the forecast in the Port Douglas area could not be supported by a network that is not part of the interconnected national electricity system. Therefore, a SAPS option is not technically feasible.

4.3.2. Demand Management (Demand Reduction)

Ergon Energy's Demand & Energy Management (DEM) team has assessed the potential non-network alternative (NNA) options required to address the identified need.

Credible options must be technically and commercially viable and must be able to be implemented in sufficient time to satisfy the identified risk to the public and/or the network due to the identified constraints.

The DEM team has completed a review of the CRAI customer base and considered the suitability of a number of demand management technologies. However, as the identified need is for reliability corrective action, it has been determined that demand management options would not be viable propositions for the following reasons.

Network Load Control

The residential customers and commercial load appear to drive the daily peak demand which generally occurs between 4:00pm and 7:00pm.

There are 601 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 360kVA[10] is available.

CRAI does not have remote LC functionality and the Tariff 33 and 31 hot water LC channels are controlled locally at each premise via time clocks on a fixed timetable. Therefore, network load control would not sufficiently address the identified need.

4.3.3. Demand Response

Four methods utilising demand response technology for deferring network investment are: Call Off Load (COL), Customer Embedded Generation (CEG), Large Scale Customer Generation (LSG) and customer solar power systems.

Customer Call Off Load (COL)

COL is an effective technique for deferring network investment where the need is for a short time period. However, in this instance, the need is required on a long-term permanent basis. There are

[10] Hot water diversified demand saving estimated at 0.6kVA per system

a small number of large customers in the catchment area but the $/kVA funding available for demand reduction is low therefore customer call off load has been assessed as not a viable proposition as it will not address the identified need, nor benefit the community.

Customer Embedded Generation (CEG)

CEG is an effective technique for deferring network investment where the need is for a short time period. The primary driver for investment in this instance is asset safety and performance. A short-term deferral of network investment by using CEG is not a technically or financially feasible option (due to the number of contracts required to be negotiated and managed).

This option has been assessed as technically not viable as it will not address the identified network requirement.

Large-Scale Customer Generation (LSG)

LSG sites such as renewable energy generation, solar or wind farms of multiple MW's capacity constitute an opportunity to support substation investment by reducing demand on, and potentially providing reactive power support for substation assets.

This option has been assessed as technically not viable as there is no known existing LSG or proposed LSG that could address the identified network requirement.

Customer Solar Power Systems

A total of 1052 customers with solar photo voltaic (PV) systems for a connected inverter capacity of 8,797kVA.

The daily peak demand is driven by residential customers and commercial load and the peak generally occurs between 4:00pm and 7:00pm. As such customer solar generation does not coincide with the peak load period.

Business customers with large solar arrays are deemed to present a significant opportunity for targeted load control or load curtailment if coupled with a Battery Energy Storage System (BESS). Contracting such customers is attractive as they represent a larger load across fewer customers and therefore are cheaper and easier to engage and contract.

PV systems with BESS present a future portfolio opportunity for potential demand response but currently this supply area has a very limited solar/BESS. Solar customers without a BESS will not meet the technical needs of the demand reduction as their solar contribution may not be available when the network un-met need is required.

4.3.4. SAPS and Non-Network Solution Summary

Ergon Energy has not identified any viable SAPS or non-network solutions that would provide a complete or a hybrid (combined network and non-network) solution to provide the magnitude of network support required in the Port Douglas area to address the identified need.

4.4. Preferred Option

Ergon Energy's preferred option is Option A, to replace both 132/22kV transformers and protection relays at CRAI in 2027.

Upon completion of these works the identified need would be addressed by replacing deteriorated assets at CRAI ensuring Ergon Energy continues to adhere to the applicable regulatory instruments. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure on obsolete and non-compliant assets while ensuring more efficient use of design and construction resources. This option will address the identified need, is commercially and technically feasible and can be implemented in sufficient time to meet the identified need.

The estimated capital cost of this option is $10.3 million. The estimated increase in planned annual operating and maintenance costs, compared to the counterfactual, for this option is $3.5 thousand. The estimated project delivery timeframe has design commencing in late-2025 and construction completed by mid-2027.

5. MARKET BENEFIT ASSESSMENT METHODOLOGY

The purpose of the RIT-D is to identify the option that maximises the present value of net market benefits to all those who produce, consume and transport electricity in the NEM.

In order to measure the increase in net market benefit, Ergon Energy has analysed the classes of market benefits required to be considered by the RIT-D.

5.1. Classes of Market Benefits Considered and Quantified

The following classes of market benefits are considered material, and have been included in this RIT-D assessment:

- Changes in involuntary load shedding and Customer Interruptions caused by Network Outages

5.1.1. Changes in Involuntary Load Shedding and Customer Interruptions caused by Network Outages

Involuntary load shedding is where a customer's load is interrupted from the network without their agreement or prior warning. Ergon Energy has forecast load over the assessment period and has quantified the expected unserved energy by comparing forecast load to network capabilities under system normal and network outage conditions. A reduction in involuntary load shedding expected from an option, relative to the base case, results in a positive contribution to the market benefits of the credible option being assessed.

Involuntary load shedding of a credible option is derived by the quantity in MWh of involuntary load shedding required, assuming the credible option is completed, multiplied by the Value of Customer Reliability (VCR). The VCR is measured in dollars per MWh and is used as a proxy to evaluate the economic impact of unserved energy on customers under the RIT-D.

Ergon Energy has applied a VCR estimate of $34.59/kWh for the CRAI 22kV load, which has been derived from the AER 2024 Value of Customer Reliability (VCR) values. In particular, Ergon Energy has weighted the AER estimates according to the make-up of the specific load considered.

Customer export curtailment value (CECV) represents the detriment to all customers from the curtailment of DER export (e.g. rooftop solar PV systems). A reduction in curtailment due to implementing a credible option results in a positive contribution to the market benefits of that option. These benefits have been calculated according to the AER CECV methodology based on the capacity of DER currently installed and forecast to be installed within the CRAI supply area.

5.2. Classes of Market Benefits not Expected to be Material

The following classes of market benefits are not considered to be material for this RIT-D, and have not been included in this RIT-D assessment:

- Changes in voluntary load curtailment
- Changes in costs to other parties
- Differences in timing of expenditure

- Changes in load transfer capacity and the capacity of Embedded Generators to take up load
- Changes in electrical energy losses
- Changes in Australia's greenhouse gas emissions
- Option value

5.2.1. Changes in Voluntary Load Curtailment

The credible options presented in this RIT-D assessment do not include any voluntary load curtailment as there are no customers on voluntary load curtailment agreements in the Port Douglas area. Therefore, market benefits associated with changes in voluntary load curtailment have not been considered.

5.2.2. Changes in Costs to Other Parties

Ergon Energy does not anticipate that any of the credible options included in this RIT-D assessment will affect costs incurred by other parties.

5.2.3. Differences in Timing of Expenditure

The credible options included in this RIT-D assessment are not expected to affect the timing of other distribution investments for unrelated identified needs.

5.2.4. Changes in Load Transfer Capacity and the capacity of Embedded Generators to take up load

The credible options included in this RIT-D assessment are not expected to have an impact on the load transfer capacity or the capacity of embedded generators to take up load between the zone substations in the Port Douglas area.

5.2.5. Changes in Electrical Energy Losses

Ergon Energy does not anticipate that any of the credible options included in the RIT-D assessment will lead to any significant change in electrical energy losses.

5.2.6. Changes in Australia's Greenhouse Gas Emissions

Ergon Energy does not anticipate that any of the credible options included in the RIT-D assessment will lead to any significant change in greenhouse gas emissions.

5.2.7. Option Value

The AER's view is that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change, and the credible options considered by the RIT-D proponent are sufficiently flexible to respond to that change[11].

Ergon Energy does not consider that the identified need for the options included in this RIT-D would be affected by uncertain factors about which there may be more clarity in future.

6. DETAILED ECONOMIC ASSESSMENT

6.1. Methodology

The RIT-D requires Ergon Energy to identify the credible option that maximises the present value of net economic benefit to all who produce, consume and transport electricity in the NEM.

Accordingly, a base case NPV calculation of the credible option has been undertaken.

6.2. Key Variables and Assumptions

The economic assessment contains anticipated costs of providing, operating and maintaining the option as well as expected costs of compliance and administration associated with the option.

The present value comparison summary includes all costs directly associated with constructing and providing the option. This includes the cost of land and easements currently owned or to be acquired for network augmentation.

6.3. Net Present Value (NPV) Results

An overview of the NPV results is provided in Table 2. The only credible option assessed, Option A, shows a positive net NPV of $90,008,000 and is the recommended development option to address the identified need.

Option	Option Name	Rank	Net NPV	Capex NPV	Opex NPV	Benefits NPV
A	Replace both 132/22kV transformers and protection relays at CRAI in 2027	1	$90,008,000	-$9,546,000	-$81,000	$99,635,000

Table 2: NPV results table

[11] AER "Regulatory Investment Test for Distribution Application Guidelines", Section A8.
Available at: https://www.aer.gov.au/industry/registers/resources/guidelines/regulatory-investment-test-distribution-application-guidelines

7. CONCLUSION

The FPAR represents the final stage of the consultation process in relation to the application of the RIT-D.

Ergon Energy intends to take steps to progress the preferred option to address the identified need.

7.1. Preferred Option

Ergon Energy's preferred option is Option A, to replace both 132/22kV transformers and protection relays at CRAI in 2027.

Upon completion of these works the identified need would be addressed by replacing deteriorated assets at CRAI ensuring Ergon Energy continues to adhere to the applicable regulatory instruments. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure on obsolete and non-compliant assets while ensuring more efficient use of design and construction resources. This option will address the identified need, is commercially and technically feasible and can be implemented in sufficient time to meet the identified need.

The estimated capital cost of this option is $10.3 million. The estimated increase in planned annual operating and maintenance costs, compared to the counterfactual, for this option is $3.5 thousand. The estimated project delivery timeframe has design commencing in late-2025 and construction completed by mid-2027.

7.2. Satisfaction of RIT-D

The preferred option satisfies the RIT-D and maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM.

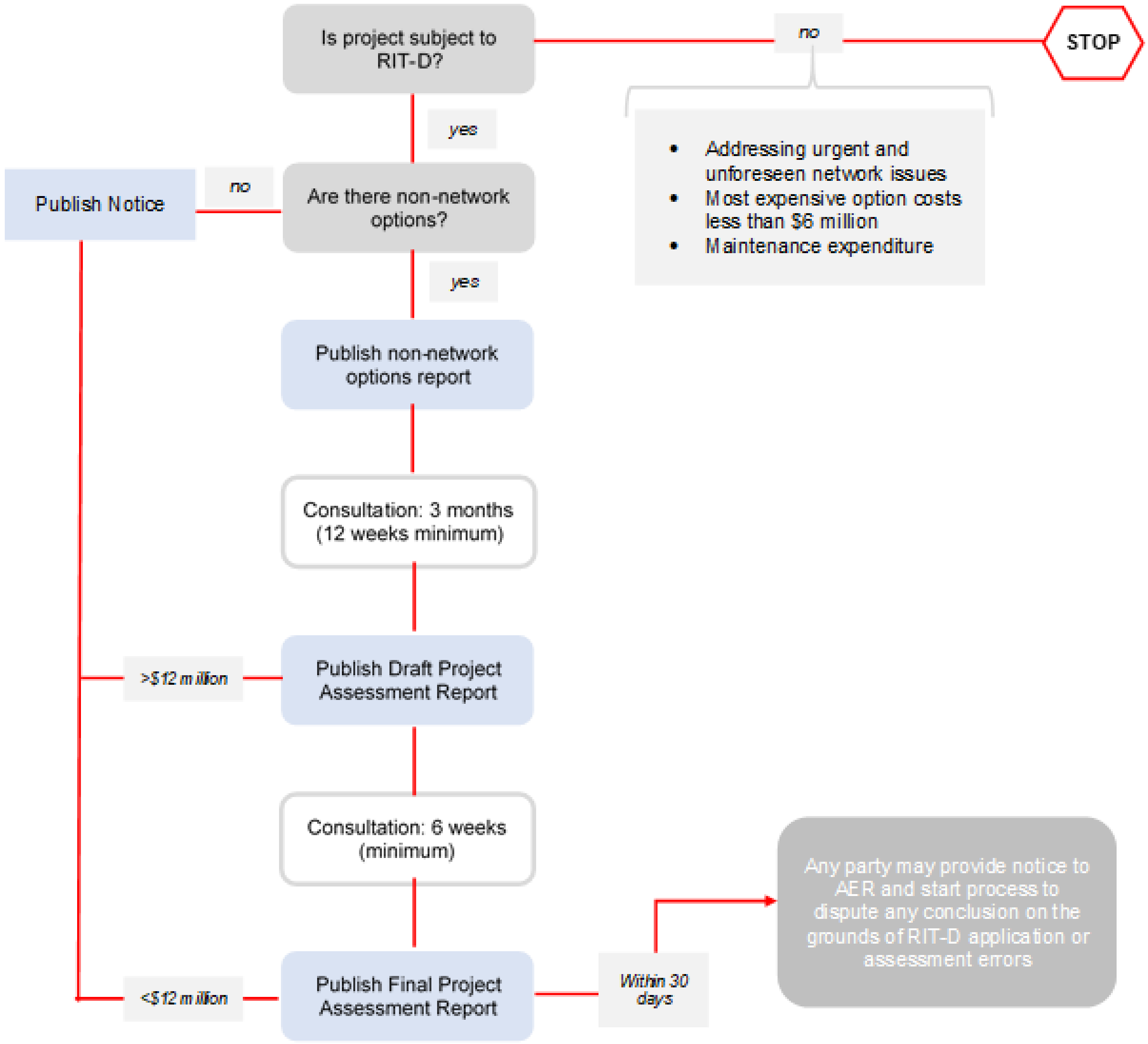
This statement is made on the basis of the detailed analysis set out in this report. The preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

8. COMPLIANCE STATEMENT

This Final Project Assessment Report complies with the requirements of NER section 5.17.4(r) as demonstrated below:

Requirement	Report Section
(1) a description of the identified need for investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary;	3.3
(3) if applicable, a summary of, and commentary on, the submissions received on the DPAR;	N/A
(4) a description of each credible option assessed	4
(5) where a *Distribution Network Service Provider* has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit of each credible option	5
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	4 & 6
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	5
(8) where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option	5.2
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	6
(10) the identification of the proposed preferred option	7.1
(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (ii) the indicative capital and operating costs (where relevant); (iv) a statement and accompanying analysis that the proposed preferred option satisfied the RIT-D; and (v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	7.1 & 7.2
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the final report may be directed.	1.3

APPENDIX A – THE RIT-D PROCESS



Source: AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017, p. 64.